Government Leadership

Regional Energy Transition Accelerator (RETA)

Mid-South Canterbury - Phase One Report

June 2023

EECA
TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

1 Foreword

Climate change is the most urgent environmental challenge of our time. Right now, energy accounts for about 40% of New Zealand's emissions. Around a third of New Zealand's overall energy use is creating heat for processing – and 60% of this is fossil-fuelled.

EECA's second Regional Energy Transition Accelerator (RETA) programme, for Mid-South Canterbury, aims to develop and share a well-informed and coordinated approach to help fast-track regional decarbonisation. Our analysis has shown that 75% of potential emissions reductions in the region are economic before 2025 – with various barriers like the availability of infrastructure preventing this occurring at the speed that it should.

RETA seeks to support organisations in Mid-South Canterbury to eliminate as much as possible of their process heat emissions through demand reduction, thermal efficiency, and fuel-switching. The work leverages the site-specific decarbonisation pathways developed for organisations across the region through EECA's Energy Transition Accelerator (ETA) programme.

Understanding unique region-specific needs, opportunities and barriers is critical. Decisions about investment in infrastructure that meets future demands requires coordination that takes into account the collective impact of decisions across multiple individual sites.

This phase one Mid-South Canterbury RETA report has provided a common set of information to all organisations considering process heat decarbonisation or who have the potential to support the transition through scaling supply of renewable energy. It clearly demonstrates that the collective effect of customers' fuel switching decisions will have significant effects on investment in these regional resource and infrastructure systems, including how this investment is prioritised and staged.

EECA believes that true progress requires working together across government, council, economic development agencies, business, and community. And the outlook is positive, with industry in the wider region highly engaged.

We are proud to have worked so collaboratively with Venture Timaru and several key groups including our RETA workstream leads, Transpower, Electricity Ashburton, Alpine Energy and Network Waitaki, Ngāi Tahu, regional forestry companies and wood processors, electricity generators and retailers, and medium to large industrial energy users, to develop this Mid-South Canterbury RETA report.

We must commit to doing more, faster, to meet what is the biggest challenge of our time. For the public good first and foremost but also, to help businesses and regions across New Zealand get ahead of the curve and thrive in a low emissions economy.

There is significant carbon reduction potential in Mid-South Canterbury – given the reliance on coal, a budding biomass industry and proactive and engaged process heat users – many of whom have already mapped out a pathway with EECA. We look forward to walking alongside the region as it continues its journey.

Nicki Sutherland
Group Manager Business, EECA

EECA

Photo: Port of Timaru - Canterbury, New Zealand. Credit - Venture Timaru.

> *There is significant carbon reduction potential in Mid-South Canterbury*
>
> Nicki Sutherland , Group Manager Business, EECA

2 Acknowledgments

This RETA project undertaken by EECA and its partners has involved a significant amount of time, resource and input from a variety of organisations. We are especially grateful for the contribution from the following organisations:

- Process heat users throughout Mid-South Canterbury
- Venture Timaru
- Local lines companies Electricity Ashburton, Alpine Energy and Network Waitaki
- Iwi
- National grid owner and operator Transpower
- Regional forestry companies
- Regional wood processors
- Electricity generators and retailers

This RETA report is the distillation of individual workstreams delivered by our partners:

- **DETA** – process heat demand-side assessment
- **PF Olsen** – biomass cost analysis
- **Ahikā and Margules Groome** – biomass availability analysis
- **Ergo Consultants** – electricity network analysis[1]
- **EnergyLink** – electricity price forecast
- **Tonkin and Taylor** – organic waste analysis
- **Wayne Manor Advisory** – report collation, publication and modelling assistance

[1] Ergo (2023), 'South Canterbury Spare Capacity and Load Conversion Opportunity Report'.

The Mid-South Canterbury region is the focus for New Zealand's second Regional Energy Transition Accelerator (RETA).

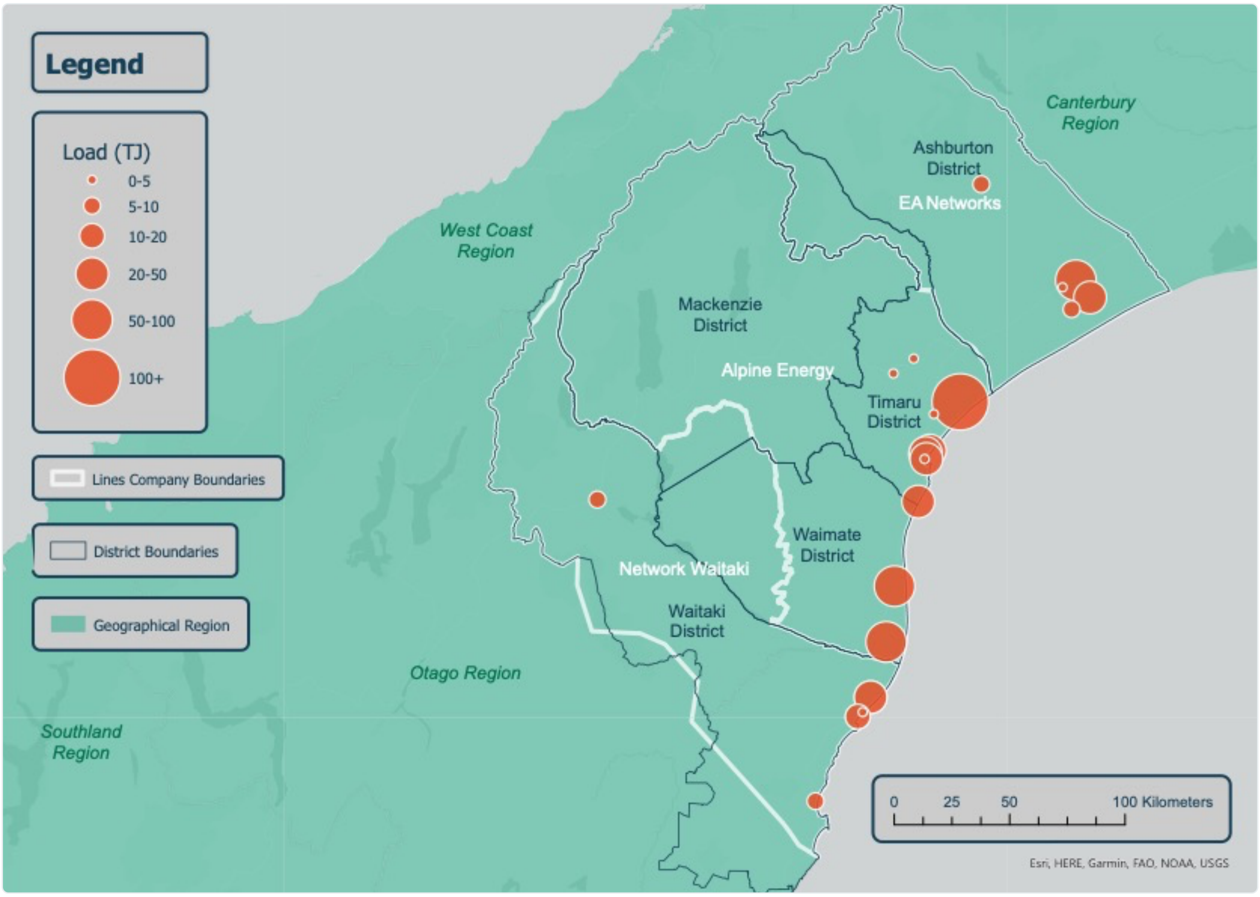
3 Table of contents

Table of contents

4 Executive summary

This report summarises the results of the planning phase of the Mid-South Canterbury (MSC) Regional Energy Transition Accelerator (RETA).

The Mid-South Canterbury region covers the Canterbury region from Ashburton south including Waitaki district.



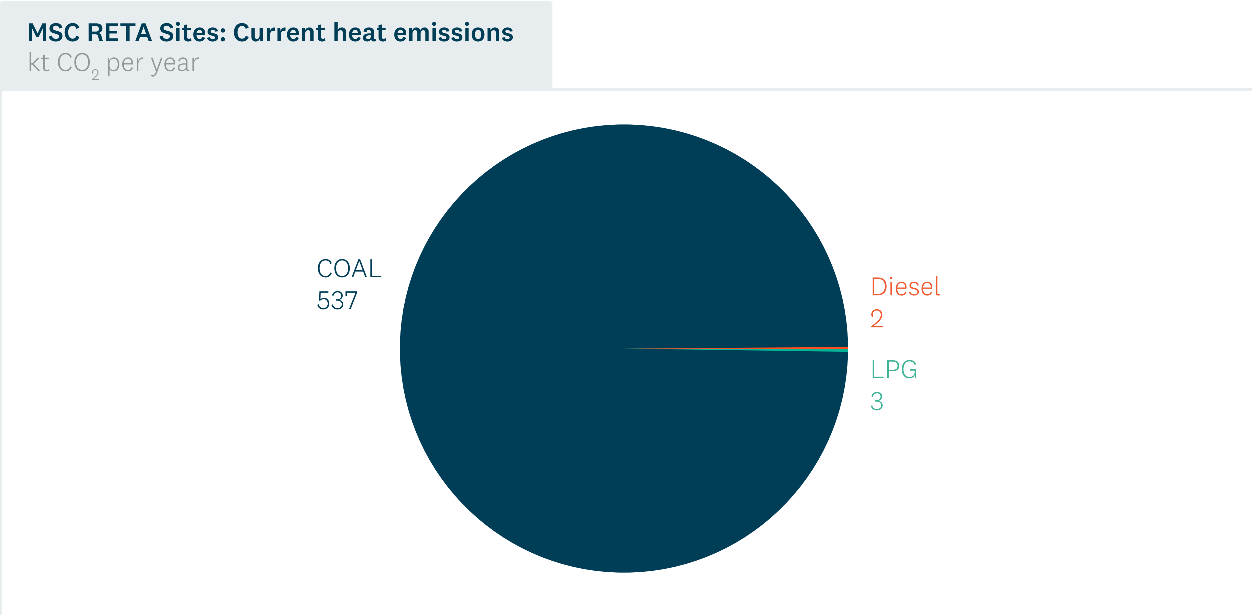
The 33 sites covered span the dairy, meat, manufacturing[2] and commercial[3] sectors. These sites either have process heat equipment larger than 500kW (i.e. process heat equipment details have been captured in the Regional Heat Demand Database) or are sites for which EECA has detailed information about their decarbonisation pathway[4]. Together, these sites collectively consume 5,731TJ of process heat energy, primarily in the form of coal, and currently produce 542kt pa of greenhouse gas (GHG) emissions.

Table 1 - Summary of Mid-South Canterbury RETA sites fossil fuel process heat demands and emissions.

Sector	Sites	Thermal Capacity (MW)[5]	Process Heat Demand Today (TJ pa)	Process Heat Annual Emissions ($ktCO_2e$ pa)
Dairy	4	207	3,450	352
Meat	7	72	970	82
Industrial	12	75	1,225	101
Commercial	10	13	86	7
Total	**33**	**367**	**5,731**	**542**

The majority of Mid-South Canterbury RETA emissions come from coal (Figure 6).

Figure 1 - 2020 Annual emissions by process heat fuel in Mid-South Canterbury RETA. Source: EECA



The objective of the Mid-South Canterbury RETA is to eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

- Demand reduction (for example reducing heat demand through process optimisation).
- Thermal efficiency (for example installation of highly efficient heat pumps).
- Switching away from fossil-based fuels, to a low-emissions source such as biomass and/or electricity.

[2] Mainly food and beverage processing.

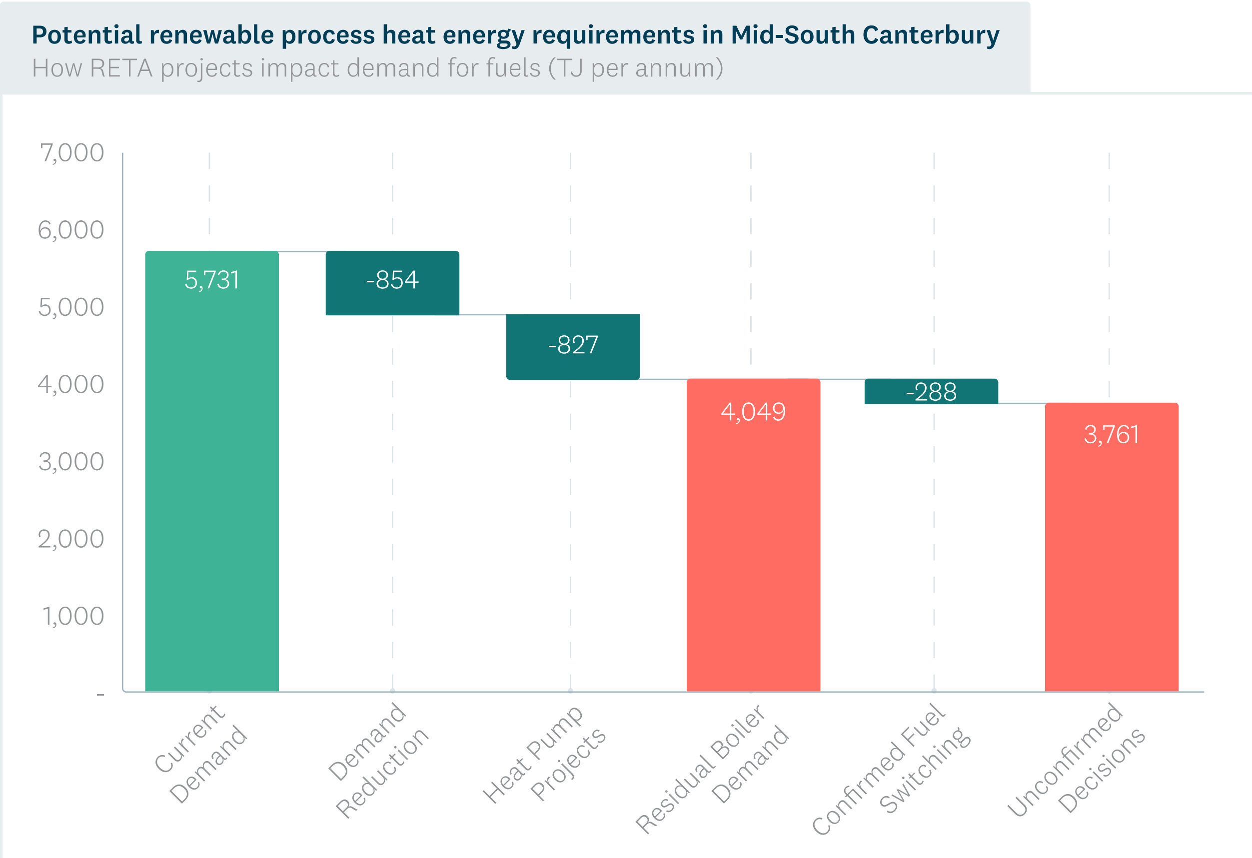
[3] The commercial sector includes schools, hospitals, and accommodation facilities.

[4] i.e. process heat equipment details have been captured in an ETA opportunities assessment report.

[5] Includes any existing electrical thermal capacity.

Figure 2 illustrates the potential impact of RETA sites on regional fuel demand, both as a result of decisions where investment is already confirmed, and decisions yet to be made.

Figure 2 - Potential impact of fuel switching on fossil fuel usage, 2022-2037. Source: EECA



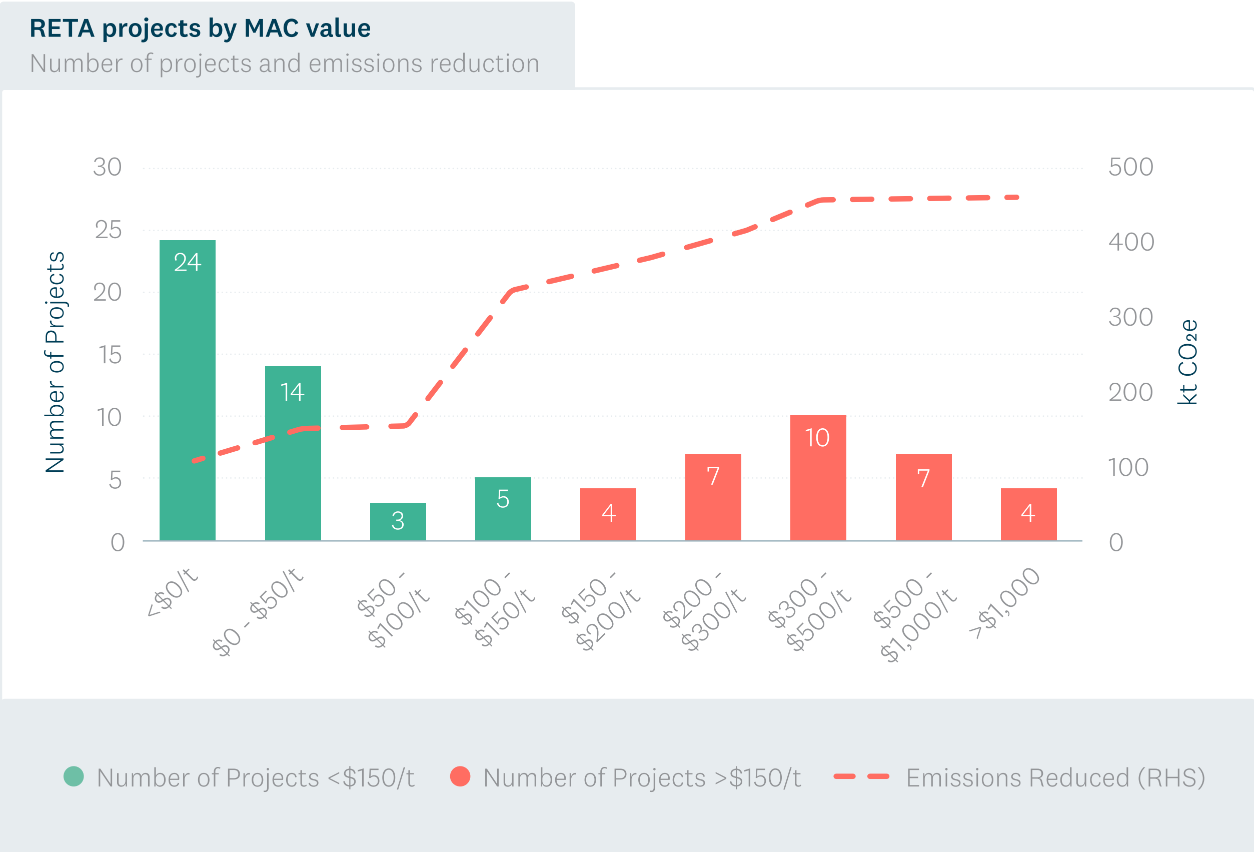
This report analyses 78 emissions reduction projects across the 33 sites – covering demand reduction, heat pump efficiency, and fuel switching projects. Further, it investigated the regional availability of biomass, electricity, and organic waste to replace coal, diesel, and LPG. Combining these two analyses – demand-side and supply-side – we can provide the indicative economics of each of the 78 process heat decarbonisation decisions.

4.1. By 2025, 75% of emissions reductions are economic

There are a range of decision criteria that individual organisations may use to determine the timing of their decarbonisation investments. Decisions are impacted by available finance, product market considerations, strategic alignment, and other factors. It is challenging to model many of these. In this report we use a simple economic criteria: at an assumed future trajectory of carbon prices (which will affect the cost of fossil fuels), at what point does a decarbonisation decision save the organisation money over the lifetime of the investment. We represent this first point in a time that the ‘marginal abatement cost’ (MAC) of the project is exceeded by the expected future carbon price.

Figure 3 summarises the MACs associated with each decision, and the emissions reduced by these projects.

Figure 3 - Number of projects by range of MAC value. Source: EECA

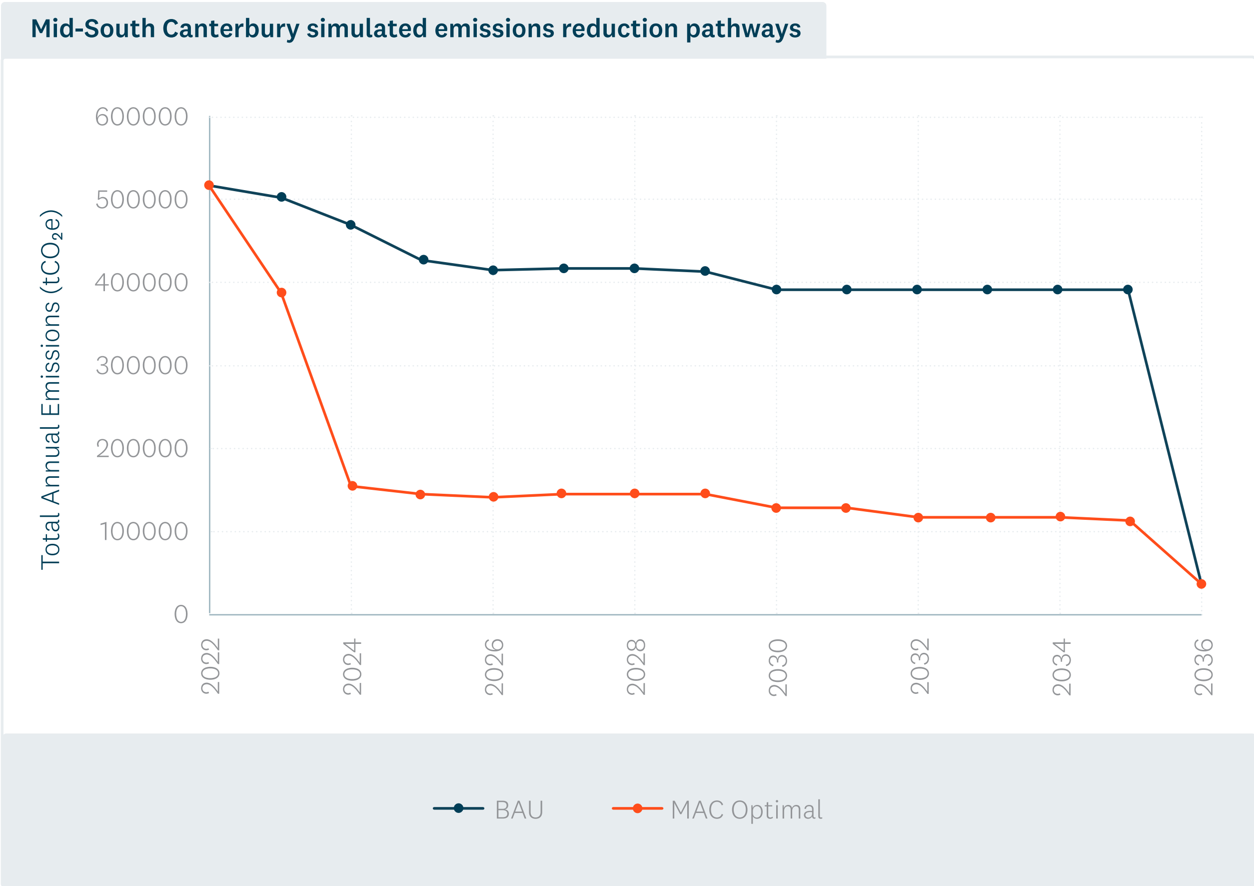


Out of 540kt of process heat emissions covered in the Mid-South Canterbury RETA, 333kt (75%) have marginal abatement costs (MACs) less than $116/tCO_2e. Based on an expectation the carbon prices will follow the Climate Change Commission's Demonstration Pathway, these emissions reduction projects would be economic[6] prior to 2025.

Compared to a scenario where each of these projects was executed based on the organisations' current plans (a 'BAU' pathway), executing these projects using a MAC decision making criteria ('MAC Optimal') would reduce the release of long-lived emission by 3.4Mt over the 15 year period of the RETA analysis (Figure 4).

[6] By 'economic', we mean that at a 6 percent discount rate these projects would reduce costs for the firms involved over a 20-year period (i.e. the Net Present Value would be greater than zero, at the assumed trajectory of carbon prices).

Figure 4 - Emissions reduction trajectories for different simulated pathways. Source: EECA



We tested a range of sensitivities on this modelling – restricted access to biomass, lower electricity prices, government co-funding, and the underlying outcome was very similar: a significant (and sometimes greater) level of emissions reductions were economic in the very near future.

Of note, government co-funding had a relatively modest impact on the pathways. However, in our modelling, the co-funding could only have an impact on the MAC value, which itself is a highly simplified way of representing these decisions. There are myriad other factors which can benefit from government co-funding. For example, many businesses have constraints on the amount they can borrow, irrespective of rates of return. The presence of decarbonisation co-funding may overcome these wider constraints, even if it has a relatively small effect on the project's economics.

Even projects that appear to be economically efficient may not occur (or not occur quickly enough) without an injection of government support.

4.2. What emissions reductions mean for fuel switching

From a supply-side perspective, the MAC Optimal pathway results in 40% of the process heat energy being supplied by biomass, and 60% by electricity.

Before outlining the fuel switching decision, it is important to recognise the significant impact that demand reduction and heat pump efficiency projects have on the overall picture of Mid-South Canterbury process heat decarbonisation.

As shown in Figure 2, investment in demand reduction and heat pumps meets nearly 30% of today's Mid-South Canterbury energy demands[7] from process heat, which in turn reduces the necessary fuel switching infrastructure required. This reduced the thermal capacity required from new biomass and electric boilers by 100MW. We estimate that demand reduction and heat pumps has thus avoided investment in $150M of electricity and biomass infrastructure.

4.2.1 Biomass

MAC Optimal biomass fuel switching projects, in aggregate, utilised all available[8] harvesting and processing residues by 2037 (Figure 5).

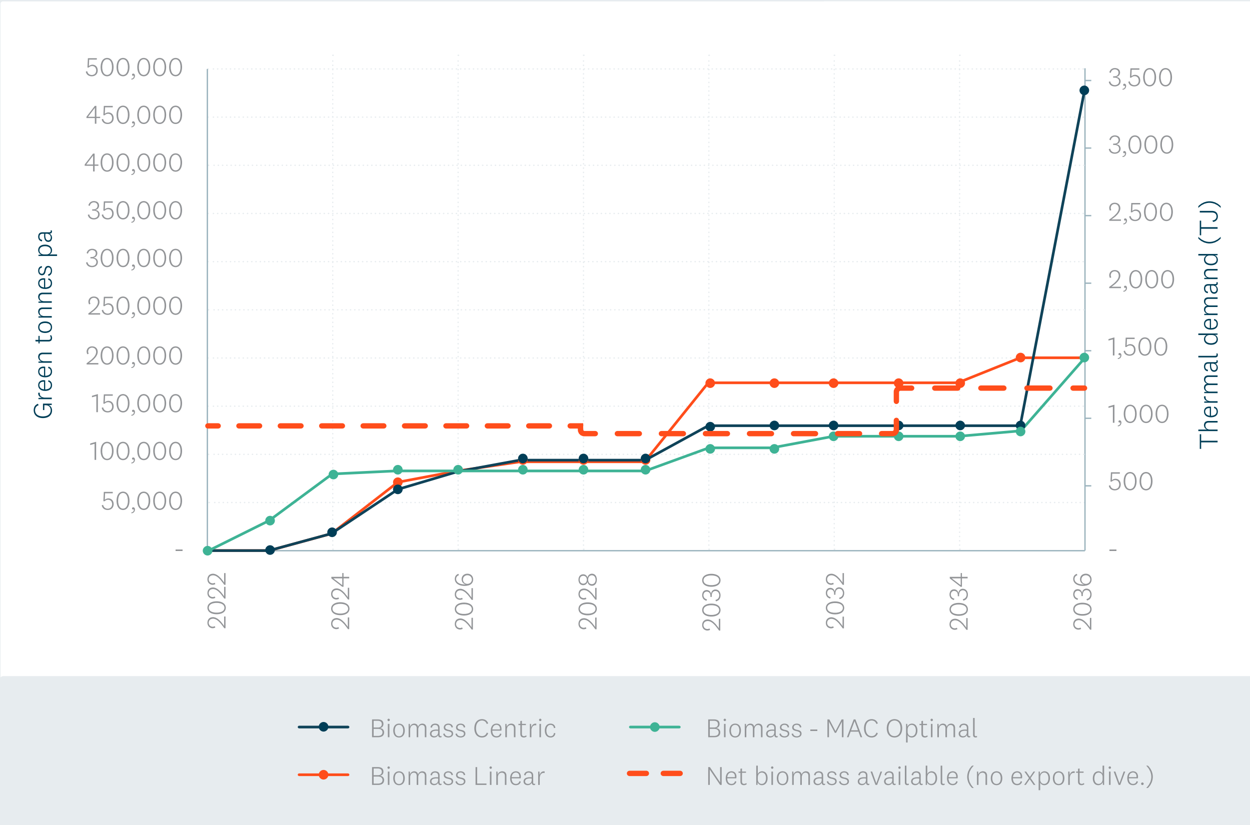
Port Blakely have demonstrated that roadside residues can be effectively recovered, stored, and transported within the Mid-South Canterbury region for bioenergy use. Beyond roadside residues, a significant quantity of residues remains in the forest (cutover). To meet the demand for biomass at lowest cost, these will need to be recovered.

[7] This is true for both energy consumption and also the peak thermal demand required from biomass or electric boilers.

[8] After deducting those being used for bioenergy today.

Figure 5 - Growth in biomass demand under MAC Optimal and Biomass Centric[9] pathways. Source: EECA

Growth in biomass demand under different simulated pathways
Green tonnes (LHS) and TJ (RHS)



Our analysis suggests that, over the next 15 years, the MAC Optimal process heat market demand for these residues exceeds $75M on a cost basis, not including chipping, storage, and transport.

Meeting demand for biomass above what residues can deliver – which is likely to be required around 2036 – would require other biomass resources. Initially, this could be the diversion of low-grade export wood to bioenergy. Should more fuel switching decisions choose biomass than what we have modelled in the MAC Optimal pathway, demand could reach a point where biomass would need to be imported from neighbouring regions.

[9] Biomass Centric is a version of the BAU pathway where all unconfirmed fuel switching projects choose biomass.

4.2.2 Electricity

Nationally, generation investment is expected to keep pace with the increase in national demand growth that arises from decarbonisation. This is likely to lead to modest increases in electricity prices for process heat consumers over the next 15 years.

However, even allowing for a 10% rise in real electricity prices over that period, 60% of the energy required under the MAC Optimal pathway chooses electricity as the best fuel.

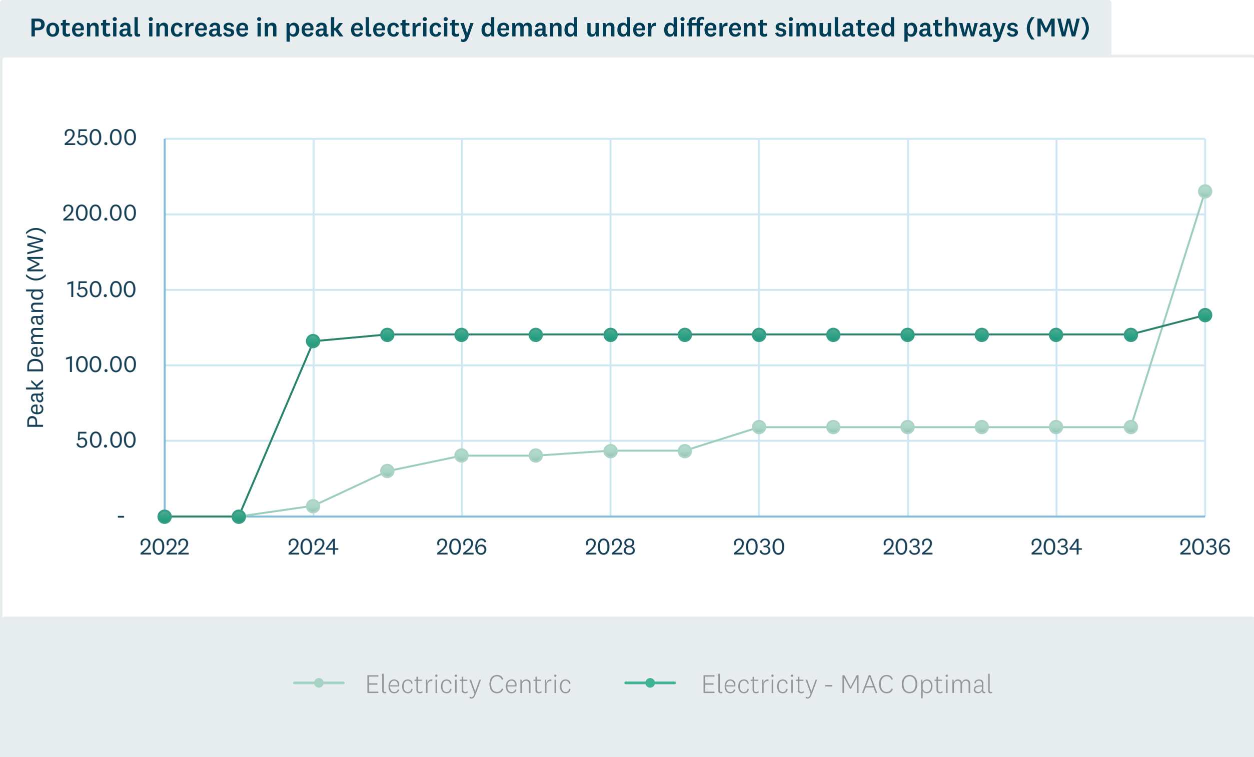
Our sensitivity analysis suggests this outcome is relatively robust under different electricity price scenarios. Part of this is due to very favourable retail electricity offers in the market today, some targeted at process heat users who convert to electricity.

While the national electricity market is expected to deliver the necessary generation to meet the increased demand from process heat, the 33 sites in the RETA study rely on an extensive network of transmission and distribution infrastructure to deliver this power to their site.

The Mid-South Canterbury is home to three distribution network owners - Electricity Distribution Businesses (EDBs) – who maintain the myriad assets that connect consumers to Transpower's national grid. They also work with Transpower to ensure that the national transmission grid is sufficient to cope with increased demand. These four entities are facing increased demands from the region as the economy and population grows, but especially as consumers consider the electrification of transport and process heat. In this growth context, each of these three EDBs oversee networks that have quite different characteristics; some currently have sufficient headroom to accommodate some decarbonisation, whereas others are facing imminent constraints not only on their networks, but also in the assets – owned by Transpower – that serve them. This RETA process has accelerated discussions between Transpower, EDBs and large process heat users to identify the necessary and optimal upgrades to the region.

The critical aspect of electricity demand growth that concerns network owners is not the growth in electricity consumption resulting new electric boilers and heat pumps (around 12% of current Mid-South Canterbury electricity demand), but the impact on the network's peak demand that arises from electrification of boilers (Figure 6).

Figure 6 - Potential increase in peak electricity demand under MAC Optimal and Electricity Centric[10] pathway. Source: EECA



This shows that – should electrification decisions proceed according to our MAC Optimal pathway – the increase in demands on the three Mid-South Canterbury EDBs would be significant. Table 2 breaks this down by EDB.

Table 2 - New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways.

EDB	Electricity Centric Pathway		MAC Optimal Pathway	
	Connection Capacity (MW)	Connection Cost ($M)	Connection Capacity (MW)	Connection Cost ($M)
EA	29	$5.38	15	$3.77
Alpine	76	$16.48	38	$6.54
Network Waitaki	13	$4.85	12	$4.85
Transpower	91[11]	$51.90	91	$51
Total	**209**	**$78.61**	**154**	**$65.75**

[10] Electricity Centric is a version of the BAU pathway where all unconfirmed fuel switching projects choose electricity.

[11] Fonterra is converting all four boilers at Clandeboye to electric. Ergo's analysis showed that the only practical way to do this was to divert the load from Alpine's network and connect directly to Transpower's grid at Orari. Technically, this would result in a small reduction in Alpine's peak demand (resulting from the disconnection of Fonterra's current electricity demand), but we do not have data on what that is.

Alpine Energy is likely to experience the most significant relative increase in network demand as a result of process heat electrification. The connection capacity sought from the Mid-South Canterbury RETA process heat sites, shown in Table 2, does not represent the predicted increase in network peak demand arising from the connection of these sites; due to diversity in the timing of each site's peak demand, the impact on the network peak should be lower. However, using Table 2's figures as an upper bound, the electrification of Mid-South Canterbury RETA sites in Alpine's network could increase their total network peak demand by between 33% (MAC Optimal) and 66% (Electricity Centric). In the MAC Optimal pathway, most of this increase would – ideally, from a decarbonisation perspective – occur in the next two years.

From the process heat user's perspective, this report also analyses the cost and complexity of securing sufficient local capacity to electrify their boilers. For nearly 80% of the sites considering electrification, the 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Most of these minor upgrades would have costs between $3M and $5M, and lead times of between 12-18 months, but a small number require equipment that is currently subject to longer lead times.

The remaining 20% of sites require more substantial upgrades, with commensurately higher cost and longer lead times.

Both the cost faced by process heat users to connect their electric boilers to the network, and the wider network upgrades that Transpower and the EDBs are contemplating, could be reduced by harnessing the potential for process heat users to be flexible about when they use their boilers. We highlighted above how demand reduction and heat pumps have reduced the need for around 100MW of thermal capacity at each site. Similarly, if process heat users could shift some or all of their electricity consumption away from critical peak times on the network (usually winter mornings and evenings), or maintain an alternative supply of fuel, a greater degree of cost savings could be experienced. Some studies have estimated sites could save between 8% and 18% of their electricity procurement costs, and between $150,000 and $300,000 per MW of electricity infrastructure costs every year.

4.3. Recommendations and opportunities

In summary, our analysis has highlighted a range of opportunities and recommendations which would improve the overall process heat decarbonisation 'system'. These recommendations are summarised here. Recommendations to improve the use of biomass for process heat decarbonisation:

- **More analysis, and potentially pilots, are conducted to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering harvesting residues.**
- **Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.**
- **Analysis is required to determine the impact of recovering harvesting residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.**
- **Development of national guidance or standard, based international experience tailored to the New Zealand context regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.**
- **More in-depth analysis of competing uses of biomass for energy at a national and regional level could help future RETA studies understand the significance of these competitive pressures.**
- **Mechanisms should be investigated and established to help suppliers and consumers to see prices and volumes being traded and have confidence in being able to transact at those prices for the volumes they require. These mechanisms could include standardised contracts which allow longer-term prices to be discovered, and risks to be managed more effectively.**
- **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**

Recommendations to improve the use of electricity for decarbonisation:

- **EDBs to proactively engage with process heat users to understand their intentions and help process heat users obtain a greater understanding of required network upgrades, cost, security levels, possibilities for acceleration, use of system charges and network loss factors.**
- **EDBs develop and publish clear processes for how they will handle connection requests in a timely fashion, opportunities for electrified process heat users to contract for lower security, and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).**
- **EDBs share sufficient information about network demand to help process heat users determine whether they can limit the extent to which they increase peak demand on the network, and the nature of network security standards.**
- **EDBs to investigate how they could equitably pass on, to electrifying process heat users, the benefit of the eight-year delay in experiencing the full residual cost component of the Transmission Pricing Methodology (TPM) associated with an increased demand.**
- **Transpower expands their renewable energy hub concept beyond the supply-side to the demand-side.**
- **Retailers, EDBs and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.**
- **EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising process heat users to efficiently use any flexibility they have in their consumption.**

Recommendations to improve the overall decarbonisation system:

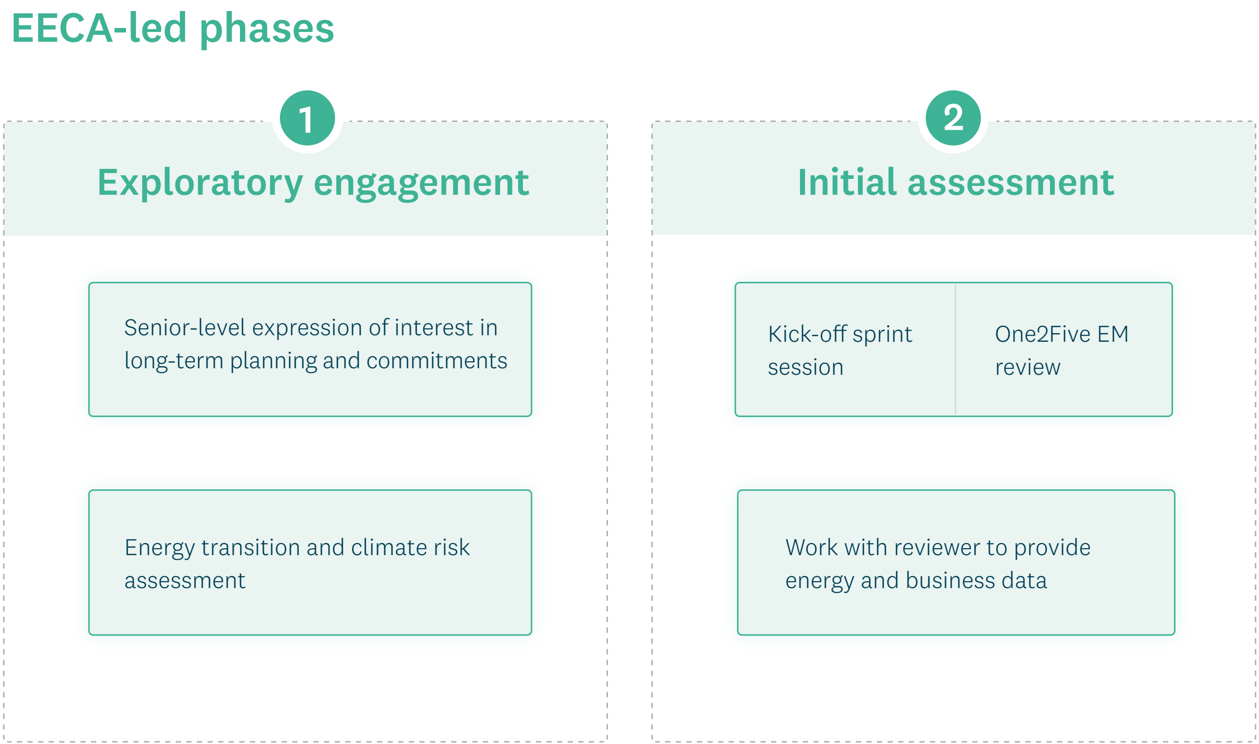
- **EECA expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**
- **Ministries (such as Ministry for the Environment) need to work with reputable organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.**
- **Process heat users enquire about government co-funding where the economics of decarbonisation are challenging; where they are economic, EECA encourages organisations to explore the potential for self-funded acceleration.**

5 Introduction

5.1. The Energy Transition Accelerator programme

EECA has run the Energy Transition Accelerator (ETA) programme since 2019. **The programme aims to support New Zealand's largest businesses to make technically and economically viable process heat decarbonisation decisions and investments which support their energy transition pathway to a low-carbon future.** EECA assists organisations in committing to a longer-term transition, based on the opportunities and risks on the economic and technological horizons. The ETA programme is designed to help businesses prepare for the future, by capitalising on the process heat energy and carbon saving opportunities that are in the pipeline now, and beyond 2030. An overview of the ETA programme is shown in Figure 7 below.

Figure 7 - Overview of ETA programme. Source: EECA



All existing EECA business tools remain available as appropriate (e.g. One2Five, business cases, feasibility studies, tech demos).

Customer-led phases

3

Detailed analysis and pathway setting

GHG accounting

Extensive energy audit

Feasibility studies

Pinch analyses

Energy management system enhancement

ETA steering group established internally

4

Planning, implementation and review

Develop and implement energy transition pathway plan

Track/review/improve

Celebrate success

The philosophy underpinning the ETA programme aligns with EECA's strategic principles:

- Focus on impact (target largest emitters)
- Understand the organisation (direct engagement and long-term support)
- Define the problem (root cause analysis)
- Join the dots (work with and connect people and organisation)
- Display leadership (pro-active action, fact-based approach)

5.2. The Mid-South Canterbury RETA

The number of companies that EECA assists in ETAs, provides the ability to use some of the individual information collected to develop an analysis of regional process heat decarbonisation pathways. This analysis informs coordination and information challenges faced by individual organisations when dealing with process heat problems that were collective in nature, such as the need for common infrastructure or new markets.

There are two stages of a RETA project – planning, and implementation. The first planning phase aims to:

- Provide coordinated information specific to the region so that process heat users can make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure.
- Surface issues, opportunities, and recommendations.

The implementation stage aims, through collaboration with regional stakeholders, to:

- Identify and address the regional barriers or opportunities in process heat decarbonisation which could benefit from government support (e.g. the Government Investment in Decarbonising Industry (GIDI) Fund).
- Identify and commit to opportunities to fast-track process heat decarbonisation projects.

This report is the culmination of the RETA planning stage in the Mid-South Canterbury region.

EECA acknowledges that the RETA focus does not consider in any detail the interaction with transport, which is also drawing on electricity (electric vehicles and hydrogen) and bioenergy (biofuels) to decarbonise. A proper whole-of-system approach would span all forms of energy demand and consider the interconnections, but this was not possible in the time available for this first, ground-breaking project. That said, this report does acknowledge obvious links to other sectors where applicable.

Further, this RETA report is based on what is known at the time of writing. We acknowledge that the nature of energy supply and demand is changing faster than at any time in history, both domestically and globally. Future iterations of RETA analyses could consider current and likely future demands from other sectors, future changes in the energy system, including new technologies, markets, and sources of energy.

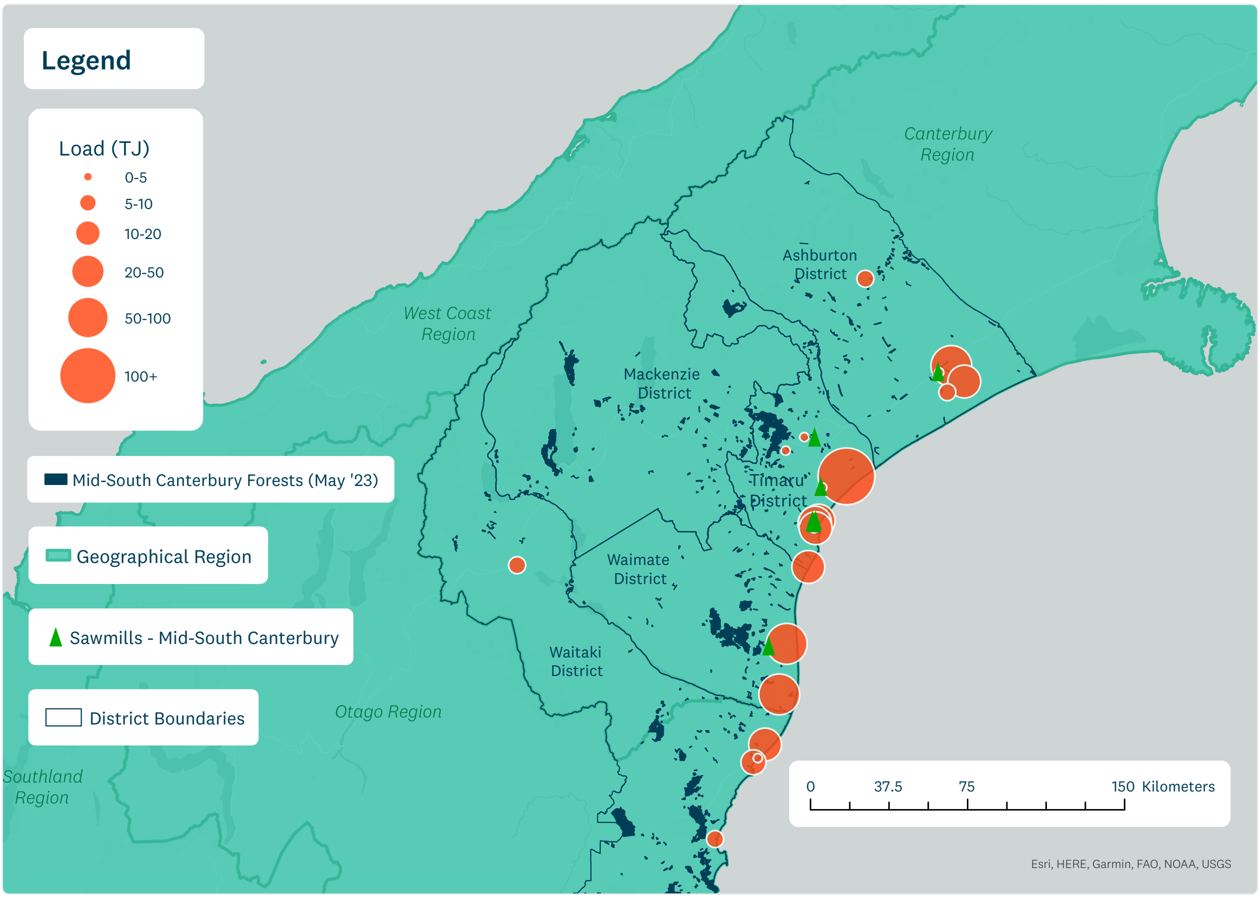

Canterbury, New Zealand

6 Mid-South Canterbury process heat – the opportunity

6.1. The Mid-South Canterbury region

The area of study encompasses Ashburton District, Timaru District, Mackenzie District, Waimate District, and Waitaki District. Figure 8 illustrates the region considered in this report, with the process heat sites located and sized according to their annual energy requirements.

Figure 8 The Mid-South Canterbury RETA Region.



6.2. Emissions coverage of the Mid-South Canterbury RETA

The Mid-South Canterbury RETA covers a total of 33 process heat sites spanning dairy, meat, industrial (e.g. sawmills) and commercial (predominantly facility heating). These are summarised in Table 3. In order to target the greatest level of emissions reduction opportunities, the sites selected represent all fossil fuelled process heat equipment above 500kW and any other sites (e.g. schools) where EECA had information from various programmes (e.g. EECA regional Heat Demand Database (RHDD)[12] and ETA) up to 2022.

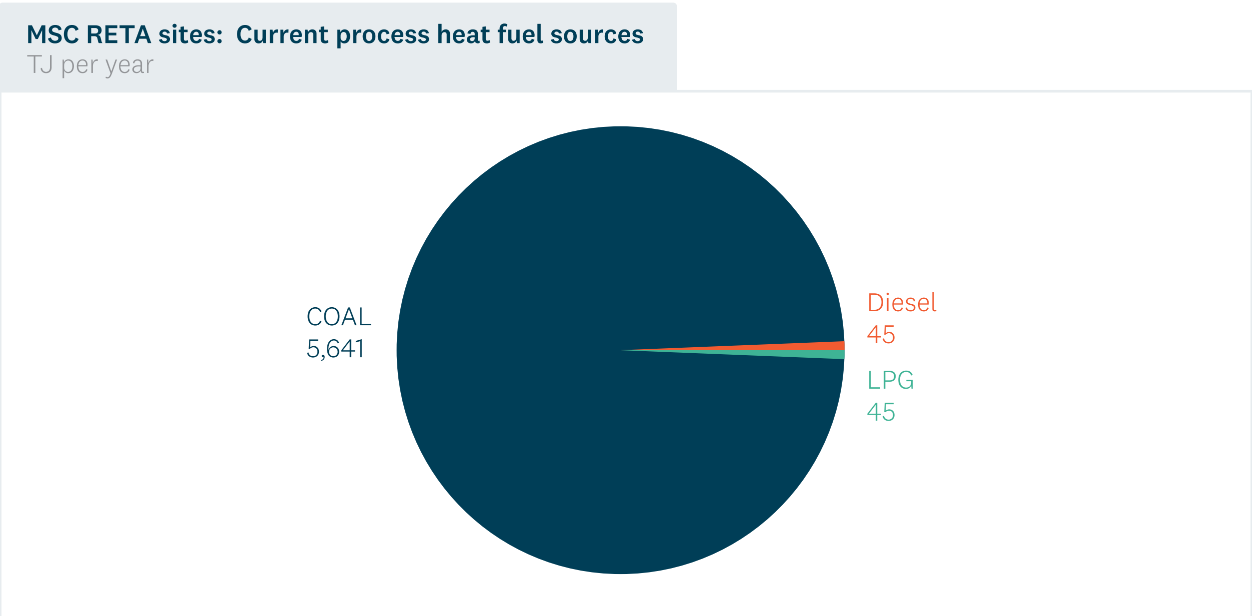
Together, these sites contribute 542kt of process heat greenhouse gas emissions (Table 3).

Table 3 - Summary of fossil fuelled included in Mid-South Canterbury RETA. Source: EECA

Sector	Sites	Thermal capacity (MW)[13]	Process heat demand (TJ pa)	Process heat annual emissions ($ktCO_2e$ pa)
Dairy	4	207	3,450	352
Meat	7	72	970	82
Industrial	12	75	1,225	101
Commercial[14]	10	13	86	7
Total	**33**	**367**	**5,731**	**542**

Current process heat requirements met by direct use of fossil fuels – coal, diesel, and LPG – consume 5,731TJ of process heat energy per year (Figure 9).

Figure 9 - 2020 annual process heat fuel consumption in Mid-South Canterbury RETA. Source: EECA



[12] See https://www.eeca.govt.nz/insights/eeca-insights/regional-heat-demand-database

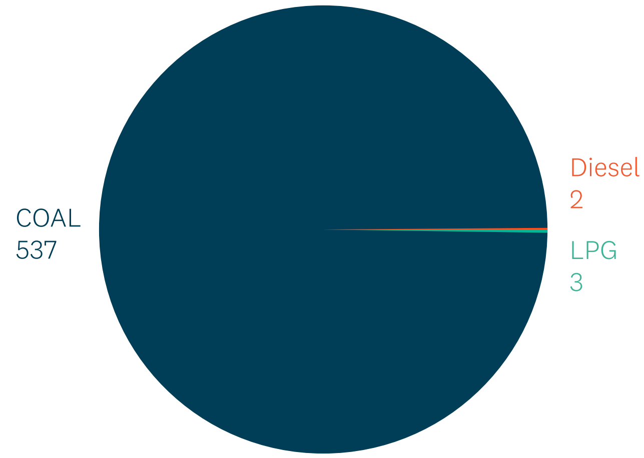
[13] Includes any existing electrical thermal capacity.

[14] The commercial sector includes schools, hospitals, and accommodation facilities.

The majority of Mid-South Canterbury RETA emissions[15] come from coal (Figure 10).

Figure 10 - 2020 annual emissions by process heat fuel in Mid-South Canterbury RETA. Source: EECA

MSC RETA sites: current heat emissions
kt CO_2 per year



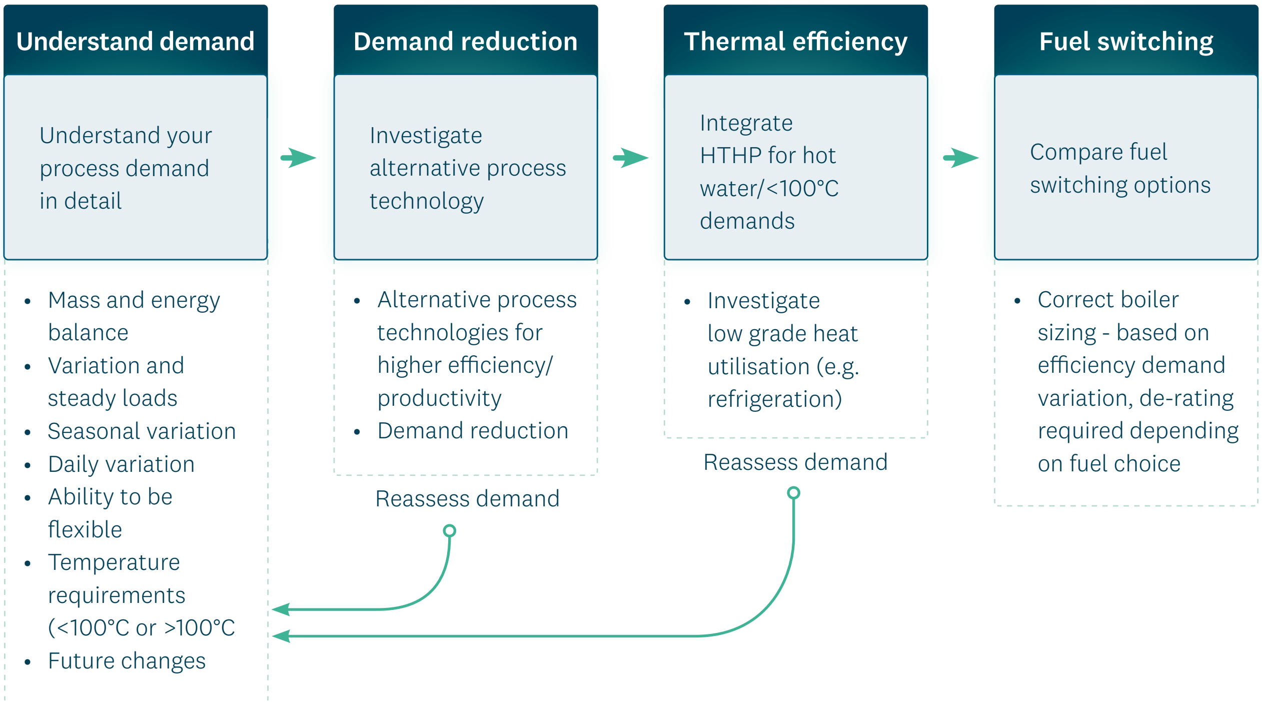
[15] Emissions factors used for fossil fuels are as follows (tCO2-e per t of fuel): Lignite: 1.43; Sub-bituminous coal: 2.01; Diesel: 2.26; LPG: 3.03.

6.3. Process heat decarbonisation – how it works

For an individual process heat user, decarbonisation is a series of interconnected decisions. While the 'fuel' decision will usually be the most financially significant aspect of the project, a number of initial steps in the decision-making process can reduce energy consumption and emissions before the major fuel switch decision is made. These steps are usually commercially attractive in and of themselves, but also may result in reducing the capital cost associated with the fuel switching decision.

Figure 11 provides an overview of the main steps in the decarbonisation decision making process.

Figure 11 - Key steps in process heat decarbonisation projects.



As part of the fuel switching step above

Electricity

- Electrode boiler
- Network capacity increase required?
- Ability to flex demand to minimise cost
- Electricity tariff

Biomass

- Age of boiler - conversion or new boiler?
- Fuel supply and price - pellets, chip, hog
- Operational requirements for different fuels
- Fuel storage requirements for different fuels

6.3.1 Understanding heat demand

A comprehensive understanding of heat requirements will underpin all subsequent decisions regarding efficiency, demand reduction, and fuel switching. An important aspect here, especially if electrification is to be considered properly, is the ability to be flexible in heat demand – can heat demand be interrupted or reduced for short periods of time (e.g. through utilising hot water storage). As will be discussed in Section 9.5, this flexibility can reduce the cost associated with any electricity network upgrades required to accommodate the project. It can also mean a financial reward for the process heat user through a variable ('time-of-use') electricity tariff. Similarly, this applies to biomass options as it avoids sizing a boiler for infrequent peak demand (if a new boiler is considered).

Understanding the nature of the site's demand, there are four primary ways in which emissions can be reduced from the process heat projects covered by the Mid-South Canterbury RETA. For any given site, the four options below are not mutually exclusive i.e. a number of options could be executed. Some of the options below are precursors for others – for example, to minimise the cost of a new boiler, demand reduction projects should proceed first.

6.3.2 Demand reduction

Demand reduction includes projects such as heat recovery, temperature optimisation, equipment replacement, thermal insulation, and water flow reduction. These projects often have lower capital costs than fuel switching, providing a good return on investment and marginal abatement cost. The ability for a site to reduce demand is specific to its operations, hence sites within the same sector usually have similar project opportunities. Opportunities in the meat industry include UV sterilisation, heat recovery, washdown optimisation, and pipe insulation[16]. For the dairy sector, opportunities could include waste heat recovery, conversion to mechanical vapor recompression, or preheating boiler feed water. These are often the best actions when considering energy productivity and the best use of limited funding.

It is critical to understand the full potential of demand reduction and best integration. Tools such as Pinch analysis could play a key role in utilising the demand reduction to its full potential.

6.3.3 Thermal efficiency – high temperature heat pumps for <100°C requirements

Improvements in thermal efficiency can be achieved primarily through the installation of high temperature heat pumps (HTHPs)[17]. As a result of their high efficiency, opportunities to use HTHPs where heat requirements are lower than 100°C are highly likely to be economically preferable to existing sources. These projects vary from site to site, but can provide heating for process water, potable water on industrial sites or HVAC on commercial sites.

Where a site has a range of heat requirements, heat pump projects should generally be considered prior to fuel switching as existing site heat can be utilised to decrease the required capacity of the new boiler. Depending

[16] See https://www.eeca.govt.nz/insights/eeca-insights/international-tech-scan/

[17] See EECA's industrial heat pump fact sheet at https://www.eeca.govt.nz/insights/eeca-insights/industrial-heat-pumps-for-process-heat/

on the site operations, a coefficient of performance (COP) of three to five can typically be achieved[18]. While not yet used in New Zealand, high temperature steam heat pumps producing 150°C heat[19] have the potential to decarbonise much of New Zealand's industry within the 15-year timeframe contemplated by EECA's RETA decarbonisation pathways for the Mid-South Canterbury region (outlined in Section 10).

6.3.4 Fuel switching to biomass – boiler conversions or replacements

Large-scale conversion to biomass will most typically draw on wood as a source of bioenergy. Within that, there is a range of options where wood is used to generate heat in a boiler.

Two primary and interrelated decisions when switching to biomass are:

- Whether the existing boiler will be replaced with a new biomass specific boiler, or the existing boiler will be converted from a coal supply chain to a wood-based one. The decision to convert an existing boiler will depend on its type, age, and condition, and may require a particular type of biomass fuel.
- What type of fuel will be used – for example, wood pellets, chip, or hog.

These two decisions involve a range of technical and financial considerations:

- If the site is converting an existing coal boiler, it may be able to be retrofitted to burn wood pellets or chip as a fuel. If a new boiler is considered, wood pellets, chip and hog are potential fuels.
- Wood pellets are a higher quality fuel and are more expensive, while wood chip and hog are lower quality fuels - but more easily produced. Wood pellets require substantially more processing than other wood fuels, and bioenergy processing plants (e.g. pellet production) will likely have minimum levels of scale to be economic and may take time to be developed in the region.
- As outlined later, EECA has not considered in detail the logistical and emissions impact of transporting biomass but notes that wood pellets will have lesser transport requirements due to their higher energy density.
- Wood fuel must have a moisture content as specified in the fuel supply contract according to the design of the boiler. Out of specification fuel may impact the performance of the boiler and the overall process.
- Hog fuel is cheaper than wood pellets and chip but may require greater modification of existing storage and handling facilities. Hog fuel may impact the boiler performance. Because of differences in the calorific value of coal and biomass, switching fuel in an existing boiler may result in reduction in maximum output rating.
- The available space on site is also important. Biomass fuel should be kept dry, so larger, covered, storage facilities may be required compared to existing coal storage.

[18] This means that one unit of electricity consumption can generate 3-5 units of heat. Heat pump systems coupled to refrigeration systems can achieve Coefficient of Performance (COPs) of 8 or more. Mechanical Vapour Recompression (MVR) technology can achieve significantly higher COP again.

[19] Fonterra is planning to trial these heat pumps. See https://www.nzherald.co.nz/business/fonterra-could-build-giant-heat-pumps-for-factories-as-1-billion-dollar-sustainability-drive-continues/LTIMLRIC2VGSVOBXTXYYHJZRGE/

6.3.5 Fuel switching – electrification

Electrification sees electrode (or similar) boilers installed to generate heat. Compared to biomass boilers, electric boilers generally have a lower capital (purchase and installation) cost, but grid-sourced electricity is more expensive than biomass as a fuel at the current time. Operationally these boilers are ~25% more efficient than biomass, with highly flexible output and low maintenance costs[20].

A key consideration when assessing electrification projects is whether the increase in electricity demand from the site requires upgrades to the local or regional electricity network. The potential cost of such upgrades is considered in Section 8.

Finally, while electrode boilers are more efficient, the electricity price is likely to be higher (on a $ per unit of energy basis) than biomass. However, electricity retailers can structure prices in a way that rewards the heat user for shifting its demand (to the extent possible) to periods where the electricity price is lower. This use of flexibility may also lower the cost of any electricity network upgrades triggered by the electrification of the process heat. This point is discussed more in Section 9.5.

[20] See https://genless.govt.nz/assets/Business-Resources/Electrode-electric-resistance-steam-generators-hot-water-heaters-for-low-carbon-process-heating.pdf

Mechanical vapour recompression system – NZ Sugar, Auckland, New Zealand.

6.4 Characteristics of RETA sites covered in this study

As outlined above, there are 33 sites considered in this study. Across these sites, there are numerous individual projects, including:

- 40 potential demand reduction projects
- 26 potential heat pump projects
- 73 potential fuel switching projects[21]

Demand reduction and thermal efficiency are key parts of the RETA process and, in most cases enables (and helps optimise) the fuel switching decision. This RETA report has a greater level of focus on the fuel switching decision, due to the higher capital and fuel intensity of this decision.

Below we show the expected remaining fuel demands from each site in the Mid-South Canterbury RETA, after any demand reduction projects and/or heat pump projects are accounted for. We present biomass demands both in TJs and wet tonnes (55% moisture content), and report the peak demand from the boiler should it convert to electricity.

Table 4 – Summary of RETA sites included in this study.

Site Name	Industry	Project Status	Bioenergy Required in TJ ('000t)	Electricity Peak Demand (MW)
McCain Foods (NZ) Ltd, Timaru	**Manufacturing**	**Confirmed**	**175 (24.3)**	**N/A**
Makikihi Fries	**Manufacturing**	**Confirmed**	**13 (1.8)**	**N/A**
Ashburton College	**Education**	**Confirmed**	**2 (0.3)**	**N/A**
Waitaki Boys	**Education**	**Confirmed**	**2 (0.2)**	**N/A**
Oamaru Intermediate	**Education**	**Confirmed**	**1 (0.1)**	**N/A**
Timaru Girls High School	**Education**	**Confirmed**	**1 (0.1)**	**N/A**
Woolworks NZ, Washdyke	**Manufacturing**	**Confirmed**	**N/A**	**9**
Canterbury Spinners Ltd, Oamaru	**Manufacturing**	**Confirmed**	**N/A**	**3**
Fonterra, Clandeboye - Boiler 1	Dairy	Unconfirmed	674 (93.8)	**40**
Fonterra, Clandeboye - Boiler 2	Dairy	Unconfirmed	556 (77.4)	**33**
Oceania Dairy Ltd, Oamaru[22]	Dairy	Unconfirmed	**342 (47.5)**	**26**
Fonterra, Clandeboye - Boiler 3	Dairy	Unconfirmed	337 (46.9)	**20**

[21] For the majority of the 33 sites, there is only one fuel switching decision to be made, usually between two fuels (biomass and electricity). These would be counted as two projects in the calculation above. However, there are several more complex sites with multiple fuel switching decisions, and some sites where only one fuel is being considered.

[22] Oceania Dairy was modelled as three projects – two chose biomass and one electrified.

Site Name	Industry	Project Status	Bioenergy Required in TJ ('000t)	Electricity Peak Demand (MW)
Fonterra, Clandeboye - Boiler 4	Dairy	Unconfirmed	337 (46.9)	**20**
Talleys, Ashburton	Manufacturing	Unconfirmed	**221 (30.7)**	14
Fonterra, Studholme	Dairy	Unconfirmed	194 (27.1)	**16**
South Canterbury By Products, Washdyke	Manufacturing	Unconfirmed	**141 (19.6)**	7
ANZCO Canterbury	Meat	Unconfirmed	**133 (18.5)**	10
Silver Fern Farms, Pareora	Meat	Unconfirmed	**74 (10.3)**	8
Alliance Group Ltd, Pukeuri[24]	Meat	Unconfirmed	**71 (N/A[25])**	**8.8**
Adrian James Harmer	Manufacturing	Unconfirmed	53 (7.4)	**1.7**
Canterbury Dried Foods	Manufacturing	Unconfirmed	46 (6.4)	**2.2**
Alliance, Smithfield	Meat	Unconfirmed	**34 (4.7)**	5.9
South Island Brewery Limited, Washdyke	Manufacturing	Unconfirmed	**18 (2.5)**	
Barkers Fruit Processing, Geraldine	Manufacturing	Unconfirmed	**13 (1.9)**	1.3
Oamaru Meats Ltd, Oamaru	Meat	Unconfirmed	**11 (1.5)**	1.1
Synlait, Talbot Forest Cheese	Manufacturing	Unconfirmed	**10 (1.4)**	1.3
Heartland Chips, Timaru	Manufacturing	Unconfirmed	**10 (1.4)**	
NZ Juice Products, Washdyke	Manufacturing	Unconfirmed	**9 (1.3)**	
Ravensdown Lime, Geraldine Quarry	Manufacturing	Unconfirmed	**6 (0.9)**	1.3
Ashburton Meat Processors	Meat	Unconfirmed	**4 (0.5)**	1
Mount Hutt College	Education	Unconfirmed	**1 (0.1)**	
Craighead Diocesan School	Education	Unconfirmed	**1 (0.1)**	
Geraldine High School	Education	Unconfirmed	**1 (0.1)**	
Roncalli College	Education	Unconfirmed	**1 (0.1)**	

Eight sites have already confirmed their fuel of choice, representing a demand for 192TJ (27,000t) of biomass and 96TJ (28GWh) of electricity.

The potential decisions associated with the remaining 23 sites will be the focus of Section 11.2. We highlight in green the preferred fuel based on the MAC Optimal calculations outlined in Section 11.1.2.

[24] Alliance Pukeuri had both biomass and electric fuel switching projects in our pathways.

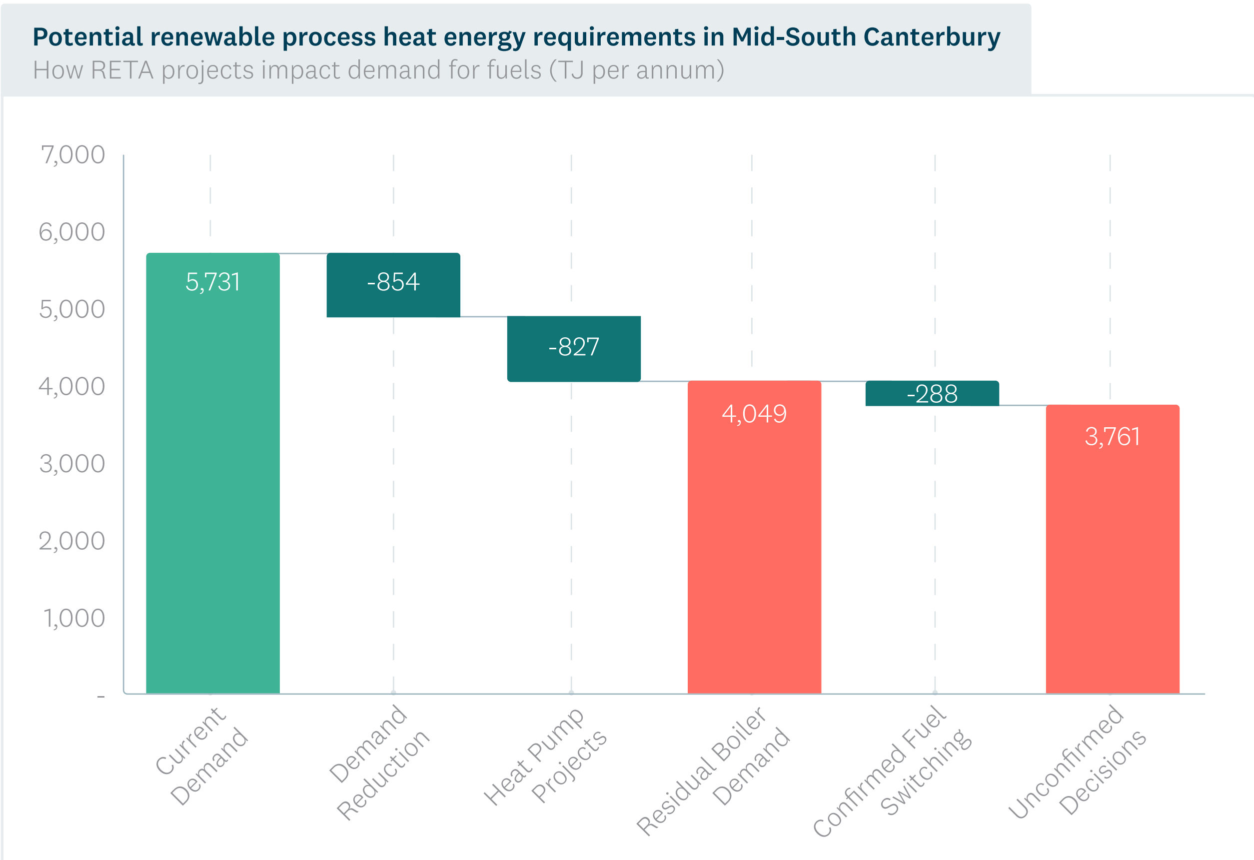
[25] Biogas is the optimal fuel for this project, and the underlying fuel for biogas was not woody biomass

6.5 Process heat energy – implications for local energy resources

All RETA decarbonisation pathways (presented in Section 11) expect that the 33 Mid-South Canterbury RETA sites, representing 5,731TJ pa of coal, LPG, and diesel process heat energy consumption in 2022, will have switched to low emissions fuel before 2037[26]. The rate at which this might occur, and the fuel choices that are made, are the subject of the rest of this report. Whichever way this occurs, the outcome has potentially significant implications for the use of various fuels and resources in the region.

As discussed above, some of the current consumption of fossil fuels by sites in the RETA study will be eliminated through demand reduction projects. Installing heat pumps could see significant efficiencies achieved, reducing the necessary size of boilers. Finally, some fuel switching investments have already been confirmed by process heat users. These components are presented in (Figure 12), to provide a picture of how fuel use may change over the period of the RETA study.

Figure 12 - Potential impact of fuel switching on fossil fuel usage, 2022-2037. Source: EECA



[26] All RETA decarbonisation projects are executed by 2037 in line with the Government's aspiration to phase out coal boilers by 2037. See https://www.beehive.govt.nz/release/government-delivers-next-phase-climate-action

As 3,761TJ of fuel switching decisions are yet to be made[27], the magnitude of change in biomass and electricity demand cannot be known with any precision. However, we can say:

- If all unconfirmed fuel switching decisions choose electricity, this could result in an increase in peak electricity demand of 218MW, if they all reached their maximum outputs at the same time. This also equates to 840GWh per annum of electricity consumption[28], approximately a 12% increase in Mid-South Canterbury's electricity demand today.
- If all unconfirmed boiler fuel switching decisions choose biomass, this – combined with confirmed biomass projects - could result in an increase of 3,950TJ, or ~550,000t, of biomass usage (see Section 8.7). This compares to our estimate that, today, around 58,000t of biomass is used for heat in 2022, i.e. a ten-fold increase in the use of biomass for heat, if sufficient resources were available.

These two scenarios paint the 'end points' of a spectrum of mixes of biomass and electricity fuel switching decisions. The reality is that each process heat user will make fuel switching decisions based on their own requirements and drivers. EECA expects that the final outcome in the Mid-South Canterbury region will be a diverse mix of electrification (both heat pumps and boilers) and biomass. These dynamics will be covered more in Section 11.

[27] The figure of 3,761TJ is slightly higher than the sum of biomass demands in Table 4. This is primarily due to the difference in efficiency between existing boilers and new boilers. The figures in Table 4 represent the fuel demand assuming a higher efficiency associated with a new boiler, whereas Figure 12 represents today's demand from the existing boilers.

[28] This includes an 80GWh increase in electricity demand from expected installation of high temperature heat pumps, the confirmed electric boiler installations, and the expected electric boiler installations.

7 Bioenergy

7.1. Approach to bioenergy assessment

This section considers the availability and potential cost of wood resources in the Mid-South Canterbury region as a potential source of bioenergy for process heat fuel switching. While there are other sources of biomass (e.g. landfills), the focus is on major sources that could collectively provide up to 500,000t - which would be the demand should all RETA sites elect to switch to biomass for process heat. While we note below that there are other sources which could complement forestry, we do not investigate these in any detail due to their relatively small volumes.

- Consider the total availability of biomass from forestry in the region, including those sources that are not currently being recovered from in-forest harvesting operations, to obtain a theoretical potential for locally sourced biomass for process heat. We adopt both a top-down and bottom-up (via interviews with forest owners) approach to this. The bottom-up analysis also provides an assessment of where the wood is expected to flow through the supply chain – via processors to domestic markets, or export markets, and acts as a check on the top-down assumptions. Interviews also highlight volumes that are currently being utilised for bioenergy purposes.

- Highlight the existing domestic and international markets for the harvested wood, either for timber products or existing demand for bioenergy (e.g. firewood) that will likely constrain (in the near term) the ability to divert wood to bioenergy for process heat.

- Consider what this analysis implies for the potential cost of delivering different types of biomass to process heat users.

- Overlay two scenarios of process heat demand for biomass from RETA fuel switching decisions, to ascertain whether this demand could be met from near term available sources, noting that the supply of bioenergy will evolve through time.

The results give a plausible view of the medium term availability of Mid-South Canterbury biomass for process heat purposes, and the foreseeable economic implications of using these resources (i.e. based on what we know at the time of writing). This has the potential to help potential users make indicative commercial judgments about the attractiveness of biomass, in the quantities required, relative to other fuel switching alternatives.

Only biomass sources within the Mid-South Canterbury region are considered. There are other regions in New Zealand where bioenergy supply potentially exceeds the demand[29]. Conceivably, these resources could be transported to Mid-South Canterbury, albeit with additional considerations and impacts (e.g. transport emissions). EECA will consider these opportunities and impacts once more regions are covered.

We are aware that process heat is not the only future user of bioenergy competing with existing markets for wood. International demand for bioenergy may increase in the future, leading to countries trading in biomass. As outlined in New Zealand's Emissions Reduction Plan (ERP), biofuels are a potential low-emission alternative to existing oil-derived transport fuels, and the ERP included an action to implement a sustainable biofuels obligation[30]. This requires further analysis, as EECA does not currently have reliable estimates for the likely local demand for biofuels[31].

7.2. The sustainability of biomass for bioenergy

The use of woody biomass for bioenergy requires careful consideration of emissions and sustainability – for example, depending on the source, the diversion of wood to bioenergy may change the timing of the release of emissions by a significant period (compared to the natural decomposition of biomass). Diversion of low-grade export wood to domestic bioenergy has an unknown global impact (via the supply chain). Suppliers and consumers of biomass for bioenergy will want to be confident they understand any wider implications of their choices.

No formal guidelines or standards exist in New Zealand at this point. There is, however, international guidance, such as:

- The Roundtable for Sustainable Biomass, Biofuels, and Biomaterials (RSB), which states that no roundwood should be used for bioenergy.
- The International Sustainability and Carbon Certification scheme (ISCC) discussed deforestation.

These international guidelines need to be interpreted carefully in New Zealand, in the context of our wider policy and regulatory context which may already be preventing some of the outcomes that the RSB and ISCC are seeking to avoid.

EECA recommends guidance is developed for the New Zealand context, drawing on international standards and experience.

[29] Halls (2018) regional resource studies show areas like the Bay of Plenty and Gisborne with more supply than demand.

[30] Ministry for the Environment, (2022), 'Aotearoa New Zealand's first emissions reduction plan', Action 10.3.5, page 190.

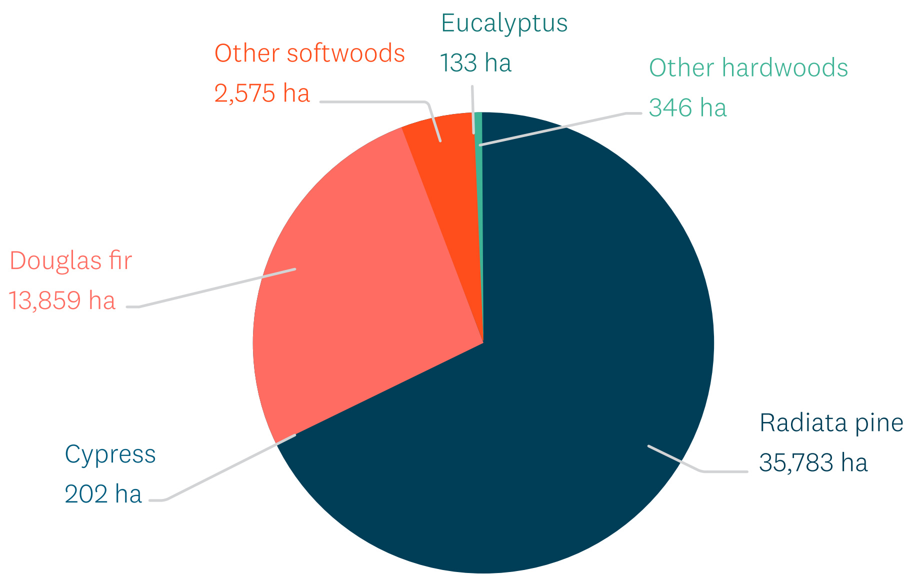
[31] An approximate estimate, from internal EECA analysis, suggests that around 1Mt of woody biomass would be needed to completely replace Southland's demand for diesel from heavy trucks with biodiesel. This assumes that Southland's diesel demand is 2.9PJ (derived from AECOM's emissions report for Great South) and conversion estimates derived from the IEA of between 2,400 and 4,000MJ/kg. We have used an average figure of 3,000MJ/kg in deriving our estimate here.

7.3. Regional wood industry overview

The Mid-South Canterbury region has approximately 53,000ha of planted forests. These forests are dominated by radiata pine and Douglas fir (Figure 13); other species include cypress, softwoods, eucalypts, and hardwood species.

Figure 13 - Area and species planted in Mid-South Canterbury (at 1 April 2021).

Area planted in Mid-South Canterbury by species



The focus of our analysis below is on radiata pine and Douglas fir, but there has been allowance for minor species in the overall resource assessment.

The forestry and food processing sector have partnered with Government to develop a Forestry and Wood Processing Industry Transformation Plan[32] which is focused on increasing the total area of forestry and getting greater value from wood. This includes significantly increasing the areas of trees on farms and domestic processing. Additional domestic processing within New Zealand may result in greater quantities of processing residues being available as an energy fuel. Increased planting of trees on farms also contributes to environmental and community benefits and is expected to occur over the next few years.

[32] https://www.mpi.govt.nz/forestry/forest-industry-and-workforce/forestry-and-wood-processing-industry-transformation-plan/

7.3.1 Forest owners

The region is dominated by one large forest owner (Port Blakely). Large-scale owners collectively own 39% of the total forested area and are summarised in Table 5. We also summarise the extent to which they are currently supplying bioenergy products.

Table 5 - Mid-South Canterbury forest estates.

	Radiata pine (ha)	Douglas fir (ha)	Minor species (ha)
Port Blakely	8,844	7,440	unknown
Ngāi Tahu Forestry	3,184	12	-
Wenita Forest Products	1,105	-	-
Laurie Forestry Mgmy	3,000	-	-
Remaining estates	19,650	6,407	3,256
Total	**35,783**	**13,859**	**3,256**

Port Blakely own the largest estate in the region. The estate is comprised of radiata pine and Douglas fir, representing one third of the Mid-South Canterbury estate. Unsurprisingly, Port Blakely is also the largest exporter of logs at Prime Port (Timaru) accounting for nearly half of annual log volumes from their own forests and purchased logs from third party forest owners.

Port Blakely already supply bioenergy into the market via bioenergy companies like Pioneer Energy and Canterbury Woodchip Supplies. Since 2018, **Port Blakely recovers 17,000t of residues from South Canterbury harvesting sites at a rate of approximately 3,500 t pa, per harvesting crew. Port Blakely store and season the residues within their forests before selling as bioenergy.**

Ngāi Tahu Forestry was established in 2000 when Ngāi Tahu Holdings Corporation purchased land subject to Crown forestry licences. The Ngāi Tahu forestry interests span many parts of the South Island, including 3,196 ha of forestry in the Waitaki District that is incorporated into this study. Nearly 95% of this area was planted less than 10 years ago.

Wenita Forest Products manage a radiata pine forestry located in the Waitaki District. This estate is small, and harvesting is managed according to economic returns instead of a corporate for steady wood flow. Nevertheless, Wenita see good potential for bioenergy from their estates and would also consider lower export grades for bioenergy if the pricing is favourable.

Laurie Forestry is a forestry management, consulting and logging company focused on growing and selling New Zealand plantation forests for the export and domestic market operating throughout Canterbury, Otago, Marlborough, West Coast with offices in Waimate, Christchurch and Blenheim. Laurie Forestry manage just under 10% of the radiata estates in Mid-South Canterbury. In addition to their export markets, local markets include firewood, post manufacturers and animal bedding.

7.3.2 Wood processors

There are 11 wood processors in the region, mostly creating products for the domestic market, using logs purchased from the forest companies. These products include building and farming products. There are no major sawmills in Mid-South Canterbury, and peelings, slab-wood and sawdust are the main residues available.

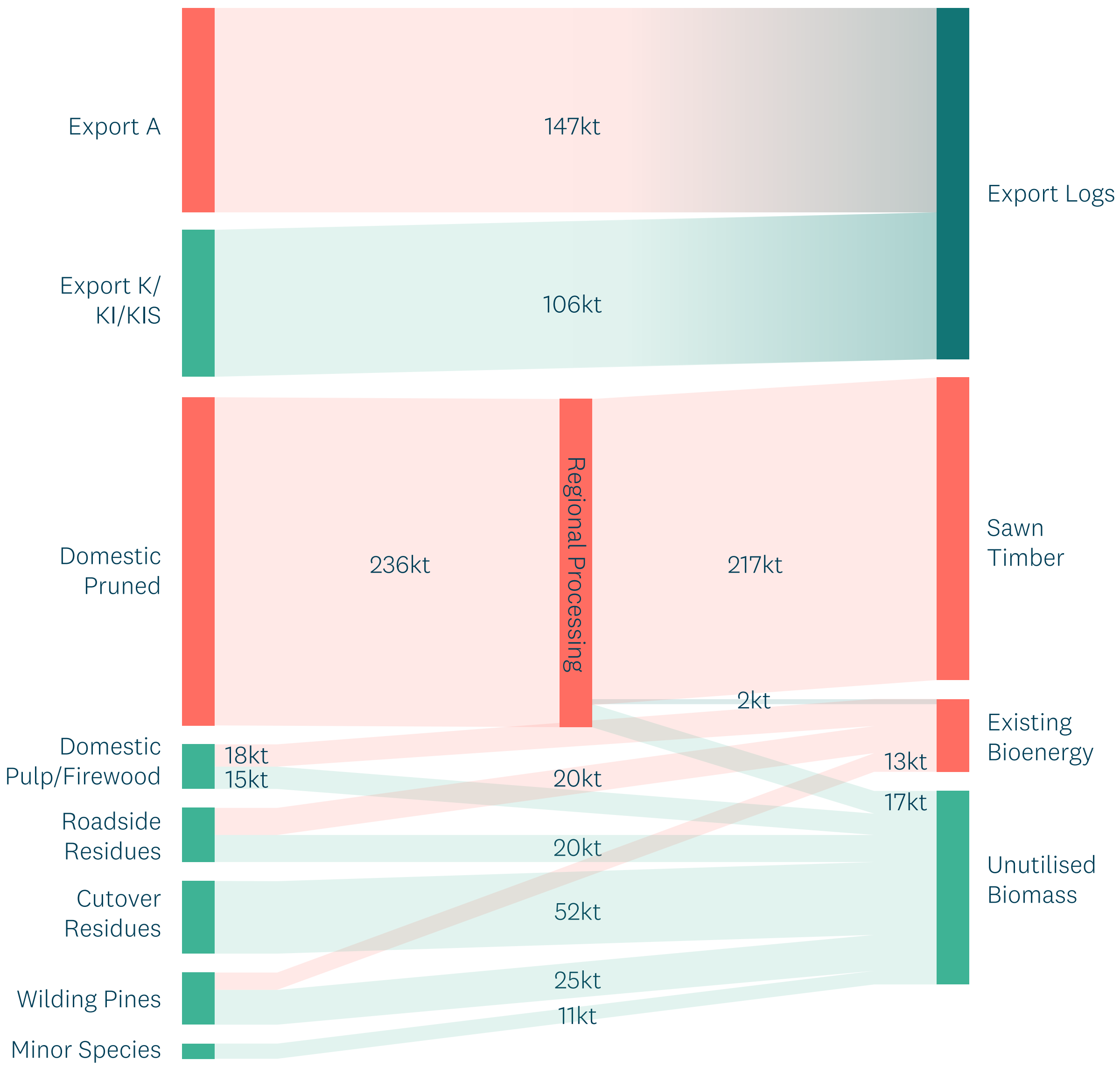
7.4. Assessment of wood availability

This section considers:

- The total wood, and the grades of wood, expected to be harvested in the region over the next 15 years.
- What are the existing markets for that wood, including the role of any processors in the region, and existing bioenergy uses.
- How much of that wood (including harvesting and processor residues) are currently unutilised.

The outcome of this analysis is summarised in Figure 4. Wood flows that could – in part or in full – be diverted to new bioenergy demand from process heat are shown in green[33].

Figure 14 - Wood flows in Mid-South Canterbury region. Source: Ahikā, Margules Groome, Wayne Manor Advisory



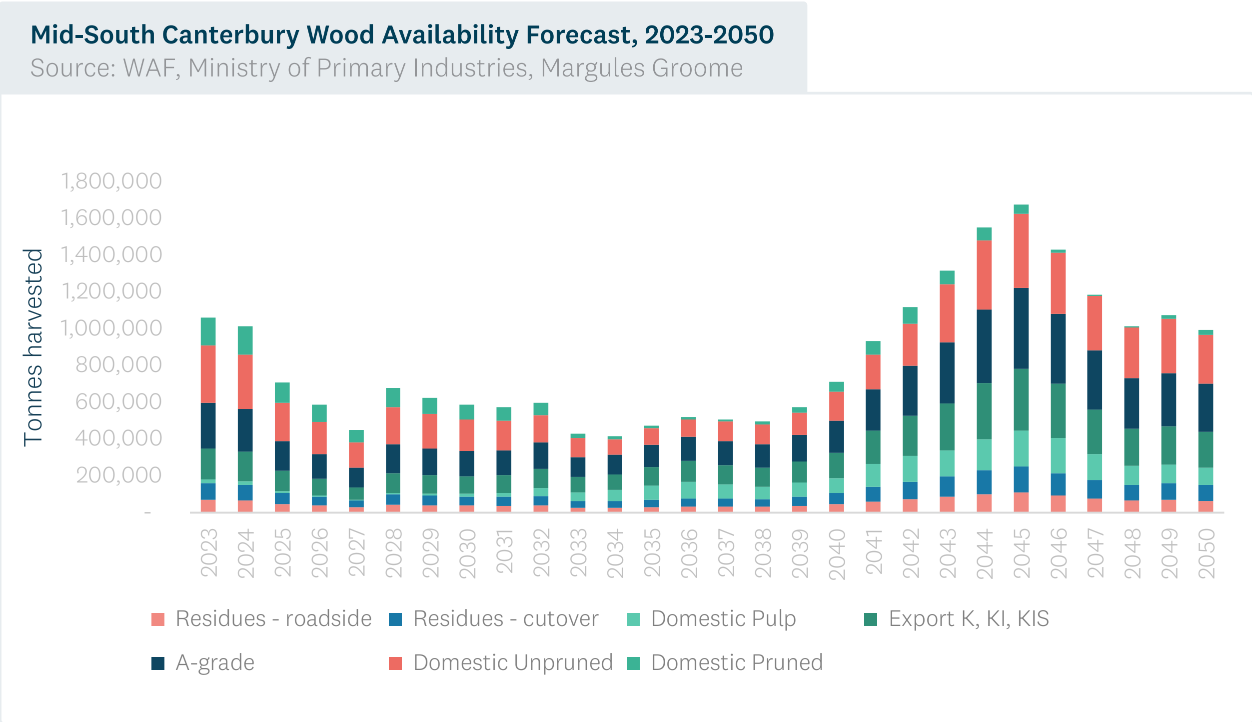
[33] Note that a large proportion of the 236kt domestic pruned wood is processed outside of the region, which is why the local availability of processing residues is a very small portion. Hence there is unlikely to be 217kt of MSC wood going to sawn timber markets; rather it would go to another region for processing and a smaller amount would finally reach the timber market. However, since we do not have data for the quantity of wood going to other regions, or the residues generated, we have not been able to depict this in the chart.

7.4.1 The Wood Availability Forecast

The Ministry for Primary Industry's (MPI) Wood Availability Forecast (WAF) provides a recognised starting point for the volume of resource that is in the Mid-South Canterbury forests, as well as when that resource is likely to come to market[34].

A single scenario for radiata pine and Douglas fir[35] was modelled and indicates the total recoverable volume from 2023 to 2050 in Figure 15.

Figure 15 - Mid-South Canterbury Wood Availability Forecast, 2023-2050. Source: WAF, Ministry of Primary Industries, Margules Groome



In Figure 15, total volumes are broken down into log grades using National Exotic Forest Estate (NEFD) data and the log-grade split for Mid-South Canterbury forest owners as provided for the WAF. Key log grades are:

- **Export grade** - This includes A, K, KI and KIS grades logs exported to Asia.
- **Domestic grade** - this includes pruned, unpruned, A and pulp log grades. These grades go to domestic markets including wood processors and firewood.

[34] These forecasts are prepared routinely for all regions of New Zealand. However, these regional boundaries do not align with the focal area of this study. To complete this forecast, permission was granted by the MPI for Margules Groome to create a forecast for the specific area.

[35] Both small and large owner volumes are smoothed to remove high levels of variability due to partial and cross-selection of two different WAF regions (Otago and Canterbury). Smoothing applied to large owner volumes as three-year rolling average (incl +one year) and to small owner volumes as five-year rolling average (incl +two years). Small owners are adjusted from the National Exotic Forest Estate (NEFD) data based on the results of University of Canterbury School of Forestry analysis of small owner area mapping c.f. NEFD areas. Small owner area over a certain age were also removed while other areas were assumed to be harvested and replanted.

- **Residues** - a by-product of harvesting and a primary source for bioenergy and firewood. It is commonly referred to as 'billet' wood; here it is split into 'roadside' (skid site, roadside and easily accessible residues) and 'cutover' (residues from stems and branches left in the forest and not as easy to access). Residue volumes are determined as a portion of total recoverable volume based on the average of estimates from harvesting studies by Hall (1994), Robertson and Manley (2006) and Visser (2010). The costs of recovering residues are discussed further below.

As can be seen from Figure 14, the total available wood resource falls steeply over the period 2023-27 and increases dramatically shortly after the end of the RETA study period (2037). This occurs due to the age distribution of the existing forests (around a third of radiata pine is less than 10 years old in this region), combined with the assumptions in the WAF model regarding when forests are harvested.

That said, a model can only predict how wood flows may occur subject to assumptions that drive individual forest harvest. It is important to recognise that forests are normally managed in a way that maximises the benefits to the owners. Such benefits are not easily modelled particularly as prevailing market conditions will change. Each owner has their own harvesting strategy based on the wood flow objectives and forest revenue. Any change in harvesting strategies by forest owners will affect the age structure and maturity of the forests they own and, in turn, future wood availability.

The harvest age can vary markedly even between neighbouring properties. The volumes forecasted by larger forest owners are subject to alteration because of changes in harvesting intentions or changes in the resource description (for example, areas and yields). But a higher level of confidence can generally be assumed for these owners than for small-scale owners, whose harvest intentions are less clear due to being more reactive, and with less accurate resource descriptions.

Large-scale owners hold 39% of the modelled resource and small-scale owners hold 61%. A key issue is the timing of harvesting by small-scale forest owners.

7.4.2 The wilding conifer estate

Wilding conifers are classified as a pest species and form a part of Environment Canterbury's (ECan) progressive containment programme. The MacKenzie Wilding estate is on reasonably accessible terrain and, despite being located 160 km from Timaru and 270 km from Christchurch, the area of forest estate makes it an attractive resource that could contribute to a region with a number of large energy users. Furthermore, the climate allows for good natural drying prior to processing.

Approximately half of the wilding estate is on Department of Conservation land and getting access to conservation land could be difficult.

Considerable progress has been made to eradicate the wilding estate, so the size of the resource has reduced considerably making it difficult to estimate the current size of the remaining estate. Of an estimated total available volume of 38,400 t pa, 12,800 is estimated to be already utilised for bioenergy[36]. Hence an additional 25,600 t pa could be made available to new bioenergy consumers.

There is potentially a much larger estate of standing dead trees that have been sprayed in the last two years. Little research is available on harvesting standing dead trees but there could be as much as 600,000t available, albeit for a much shorter timeframe[37]. This resource has not been included in the total available bioenergy volume due to the time constraints to utilise.

7.4.3 Minor species

In Mid-South Canterbury, minor species account for 3,256 ha in the NEFD. However, information regarding the status of many of these smaller holdings is sometimes poor. Ahikā and Margules Groome refined this assessment[38], resulting in a lower estimate of 1,600 ha. It is assumed whole trees are utilised for bioenergy at a rate of 350 t per hectare. Averaged over 2023-2037, and accounting for the age class distribution, minor species could thus contribute 11,000 t pa as bioenergy.

7.5 Insights from interviews with forest owners and processors

The results of the WAF modelled was complemented with a set of detailed interviews and surveys of the major forest owners. This provides a richer picture of the potential resource available for bioenergy.

7.5.1 Processing residues

All 11 processors in the region were interviewed to better understand both the potential residues from processing, as well as the current demand for these residues for bioenergy.
The main residues from wood processors are:

- **Sawdust** is the residues from sawing logs and is one of the more difficult products to sell. It can be mixed with other residues and sold as animal bedding. It could also be made into wood pellets but needs to be dried beforehand.
- **Post peelings** are the residues created from making round posts (fencing, poles, lamppost) and are thin and long in shape making them difficult to manage. Additional processing may be necessary to create a more uniform product for bioenergy.
- **Post offcuts** are from the log ends and are sold as firewood. Any remaining bark is also removed before processing. 'Slab wood' is also produced from the offcuts of milling and is sold as firewood.
- **Bark** is mostly created at the port when handling, storing, and loading logs but small volumes are also available from processors.

[36] Ahikā & Margules Groome, 2023, 'Bioenergy Availability assessment for the Mid-South Canterbury region' Report for EECA.
[37] Dead trees become brittle in a relatively short space of time, marking harvesting difficult and potentially dangerous.
[38] For example, all areas greater than 40 years old have been removed as it is assumed that they have been harvested since March 2021 or will never be harvested; and an adjustment to minimise the risk of double counting between wilding pines (covered separately in Section 7.5.2) and minor species.

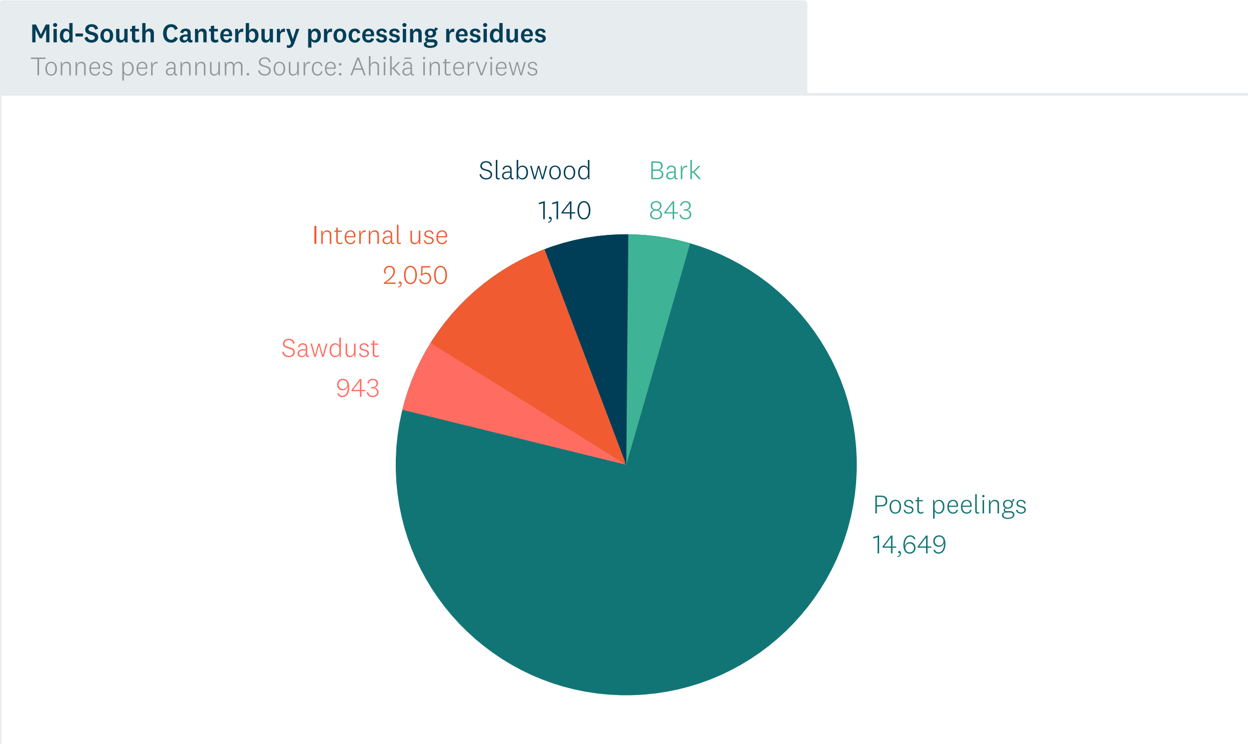
Table 6 shows the types of processing residues readily available from six of the processors interviewed.

Table 6 - Products readily available for bioenergy from processors in Mid-South Canterbury.

	Wood pellets	Sawdust	Peelings	Offcuts	Bark
Prime Port					x
Point Lumber			x		x
Great Southern			x	x	
Adams Sawmill		x		x	
Starwood Products	x				
Hedley Contracting		x		x	

The interviews conducted suggest that there are around 19,600 t of processing residues created in the Mid-South Canterbury region, the majority of which is post peelings (Figure 16). There are 2,050 t of these residues are already being utilised for bioenergy in the form of wood pellets and boiler fuel. The remainder – primarily post peelings (14,000 t) – are unutilised and are stockpiled by the processors.

Figure 16 – Mid-South Canterbury processing residues, tonnes per annum. Source: Ahikā interviews



7.5.2 In-forest recovery of biomass

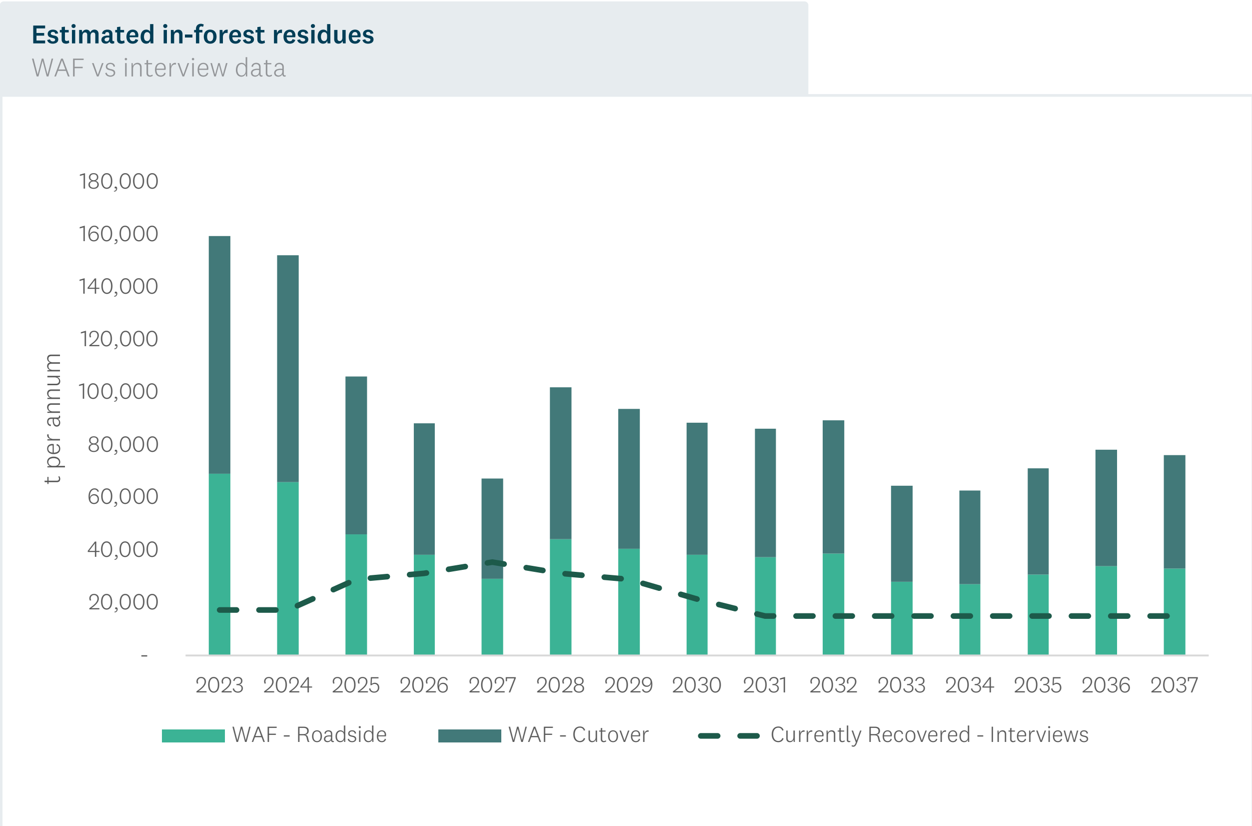
In forest residue volumes were estimated by Margules Groome as part of the WAF[39]. In-forest volumes have been split into two categories:

- **Roadside** - is described as a percentage of total recoverable volume based on the average of estimates for ground based and hauler harvesting sites for stem and branch waste from three different studies. Practically, this will include skid site, roadside and easily accessible residues.
- **Cutover** - refers to residues from stems and branches left in the area that has recently been felled and cleared and is not as easy to access. This volume is technically recoverable but at a higher cost due to the additional effort required.

Based on interviews with the forest companies and forest managers, approximately 21,150 t pa of roadside residues are already recovered in-forest and used in the bioenergy sector. The WAF estimated an additional 19,000 t pa (averaged over 15 years) of roadside residues could be economically recovered, albeit with higher volumes initially and lower volumes later on (see Figure 17).

[39] As noted above, this estimate was based on the research of Hall (1994), Robertson and Manley (2006) and Visser (2010, 2018).

Figure 17- Estimated in-forest residues WAF vs interview data.



Furthermore, there are cutover recoverable volumes of 52,300 t pa (averaged over 15 years) albeit at an additional cost. Visser (2018) suggests a rate of $45/t while interviews with forest owners and managers indicates $60/t for cutover residues. As outlined below, this report assumes a cost towards the upper end of this range ($55/t).

A more definitive estimate of cutover recovery resources and cost requires an assessment of the underlying terrain, as recovery on steep hauler country is likely to be substantially lower than on ground-based country. This information was not available for the Mid-South Canterbury RETA. With this caveat in mind, we will use the WAF estimate of volumes.

Based on conversations and interviews with the small forest owners and managers, full recovery of roadside and cutover residues for bioenergy is not happening for several reasons including:

- Absence of markets at a price that would cover the cost of recovery
- Lack of in-forest storage

The exception to this is Port Blakely's established program to recover all residues grades from their harvesting sites. All residues recovered in-forest are stored in forest, seasoned, and sold as bioenergy. There are other benefits to recovery for Port Blakely, including reduced environmental risks, landing slash reductions and productivity gains in establishment. These collective benefits resulted in Port Blakely setting up an in-forest system for managing bioenergy.

7.6 Summary of availability and existing bioenergy demand

Figure 18 below shows our overall assessment of the forest (and forestry by-product) resources in Mid-South Canterbury.

Figure 18 - Wood resource availability in Mid and South Canterbury WAF and additional analysis.

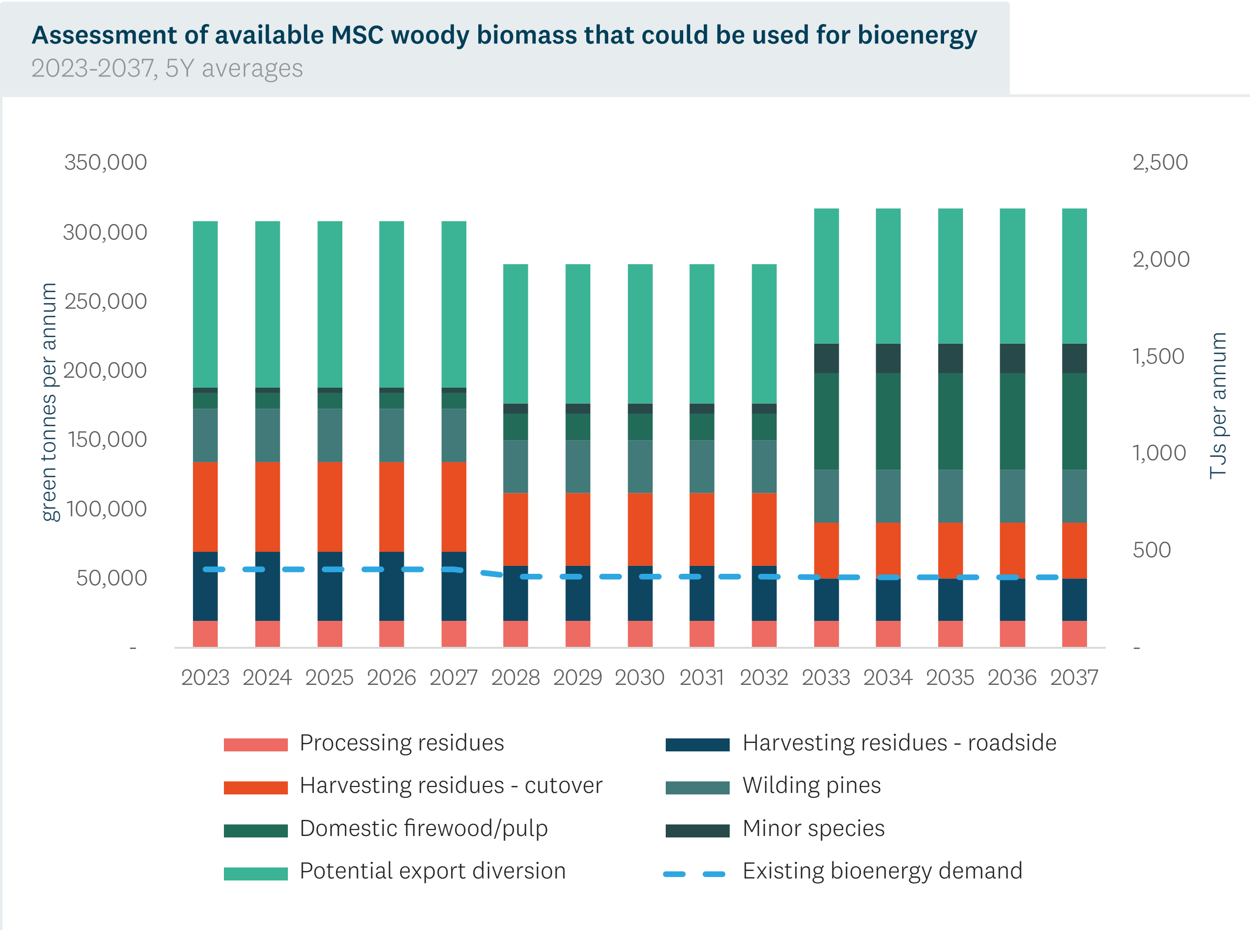


Figure 18 shows there is significant scope to increase the use of bioenergy from the relatively low level today. However, there are several factors to consider:

- Ideally, the consumption of bioenergy should not disrupt domestic markets for timber; hence domestic pruned, unpruned and A-grade timber are only shown for reference and are not likely to be used for long-term bioenergy requirements.
- The preservation of existing bioenergy users' access to fuel.
- The price of collecting, processing, storing, and delivering the bioenergy to potential users.
- The stability of the resources through time, as investors in bioenergy as a fuel will want at least medium-term certainty on availability and price.

We now turn our attention to the likely price of the potential bioenergy resources identified above.

7.7 Cost assessment of bioenergy

Since bioenergy markets are very much in their infancy, the approach is to base prices on either an estimate of the costs of extracting the resource, or to 'shadow price' to the value of resources in other markets (where these markets existed). Shadow pricing uses e.g. export prices for wood, to imply a price that has to be 'matched or beaten' if users are to divert their wood resources away from that market to bioenergy.

The three primary sources of data for this analysis were:

- Export logs and pruned sawlogs: PF Olsen analysis of AgriHQ Forestry Log Price Report (Southern South Island three-year average prices to August 2022).
- Processor residues, minor species and wilding pines: Ahika cost analysis.
- In-forest residues: Estimated in consultation with Scion, University of Canterbury, literature review, Ahika cost analysis and the local knowledge of PF Olsen.

7.7.1 Cost components

The sources listed above provided a base price for each source of biomass, delivered to a central chipping location. To provide an indication of the costs of biomass delivered to a process heat customer's site, two additional cost components must be added:

- The costs of chipping logs and in-forest residues[40] into a form suitable for boiler use, and storage of the chip. An assumption was made that there would be one central location for chipping and storage, and that costs equated to $15/m^3 for chipping and $6/m^3 for storage[41].
- Transport costs from the central chipping and storage location to the customer site. Since transport costs will vary with the distance from a single central site to any of the process heat sites, they were assumed to vary between $11/m^3 (30km) to $33/m^3 (120km).

Including these costs results in a set of prices for biomass delivered to a biomass customer. Table 7 and Figure 19 show these costs, assuming a 60km distance between a centralised chipping and storage location, and the process heat user's site. This figure is not based on any analysis of the sites and is purely for illustration purposes.

We also convert these underlying costs (in $/t biomass) to an energy equivalent ($/GJ). This requires an assumption about the moisture content of the underlying fuel. We use calorific value associated with a moisture content of 55%; in reality, the moisture content will vary between the different sources listed in Table 7; this will need more detailed consideration by process heat users contemplating conversion to biomass.

[40] Processor residues are assumed to be in a form suitable for use straight away.

[41] Estimated by PF Olsen in consultation with Scion, University of Canterbury, literature and PF Olsen experience.

Table 7 - Sources and costs of biomass resources in the Mid-South Canterbury region. Source: PF Olsen, Ahikā

Bioenergy source	Cost of biomass source ($/t)[42]	Chipping and storage ($/t)	Transport to process heat user ($/t)	Total cost delivered to user's site ($/t)	Total cost delivered to user's site ($/GJ)[43]
Processor residues	$42	$6[44]	$18	$66	$9
Roadside residues (incl. collection)	$46	$21	$18	$85	$12
Minor species	$44	$21	$18	$83	$12
Cutover residues	$55	$21	$18	$94	$13
Domestic firewood (pulp)	$65	$21	$18	$104	$14
Wilding pines	$49	$21	$41[45]	$111	$15
Export grade K, KI and KIS logs	$92 - $112	$21	$18	$131 - $151	$18- $21
Export grade A logs	$120	$21	$18	$159	$22
Pruned sawlogs	$169	$21	$18	$206	$28

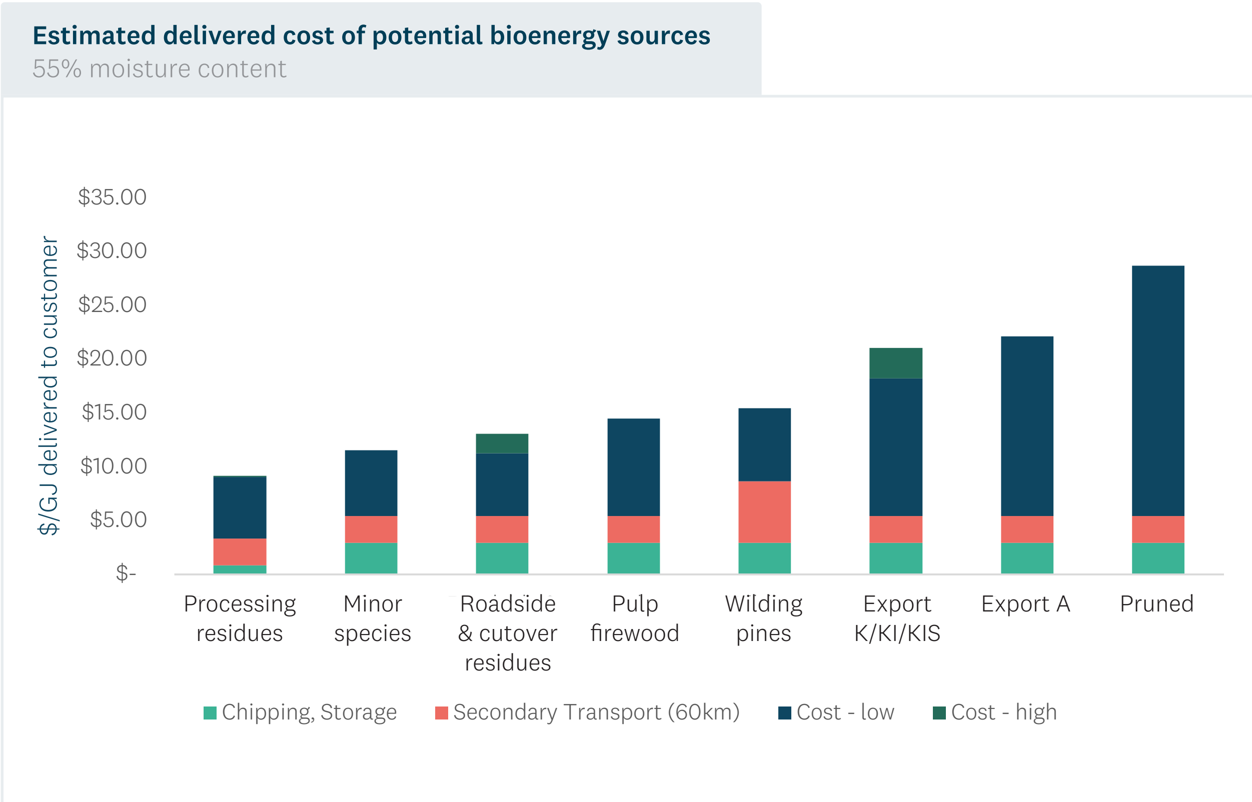
[42] Primary transport from the forest or processor site to a centralised location is factored into the delivered log or residue price At Mill Gate (i.e. incurred by the forest owner).

[43] Conversion in energy equivalent assumes a net calorific value of 7.184 MJ/kg (55% moisture content), and 1m3 = 1,000kg. We also note that this is a price of energy as delivered to the gate and is therefore not directly comparable to an electricity price, due to the relatively lower biomass boiler efficiency compared to an electrode boiler (or a high temperature heat pump, where applicable). We expand on this comparison in Section 10.

[44] Processor residues do not need chipping, only storage.

[45] Reflecting a 150km transport distance to a Mid-South Canterbury demand location.

Figure 19 - Estimated delivered cost of potential bioenergy sources. Source: PF Olsen (2022), Ahikā (2022).

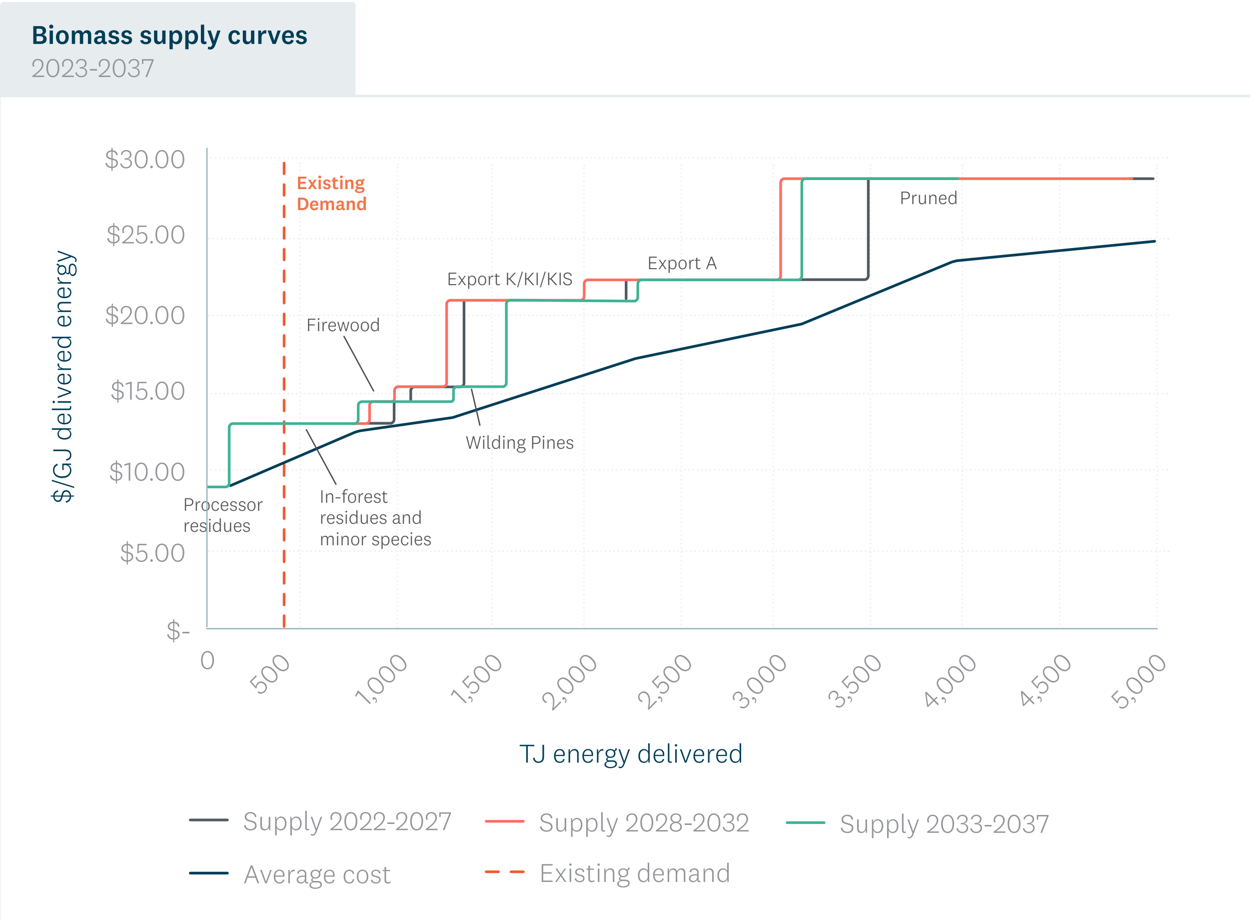


We reinforce that we retain domestic pruned sawlogs and export grade A logs in the analysis not because we believe these are sustainable or practical sources of bioenergy. Rather we use them in the supply curve to represent 'scarcity values' if our scenario analysis below should indicate that other more plausible and sustainable sources of bioenergy are insufficient.

7.7.2 Supply curves

To convert these costs into an indicative market supply curve, we use the corresponding volumes for each category of resource from the analysis in Section 8.6 above. Since the supply of near-term bioenergy resource availability varies through time, we produce three supply curves, one for each of the five-year periods in the next 15 years. This is shown in Figure 20.

Figure 20 - Biomass supply curves through to 2037. Source: PF Olsen, Ahikā



The supply curves have three dimensions: volume, cost, and time. The cost shown by the solid line for each increment in supply is the marginal cost for the most expensive resource required to meet that level of demand. This is higher than the (volume-weighted) average cost paid by the market overall at any point in time (which would include the lower cost resources). It allows us to think about the price bioenergy users may face in any year in two ways:

- If early biomass customers secure long-term contracts for lower cost processor residues or in-forest residues (indicated by the dashed lines), they will still have access to those resources, at the agreed price, for the duration of those contracts. This is regardless of what is happening in the rest of the market. As each subsequent process heat user switches fuels, they will contract for the lowest cost resource that has not already been secured by an earlier adopter. Hence the supply curves in Figure 20 indicate the price faced by the next increment of demand, assuming that all cheaper biomass resources have been fully contracted, at least for the remaining period of the chart.

- Alternatively, the biomass market may operate on a 'spot' basis, without any long-term contracting. Every year, aggregators of bioenergy resources suitable for process heat will secure the supply, and all users will pay a price approximating the average cost across all the resources.

Reality will likely lie somewhere between these two scenarios, depending on how the arrangements for long-term supply of bioenergy evolve.

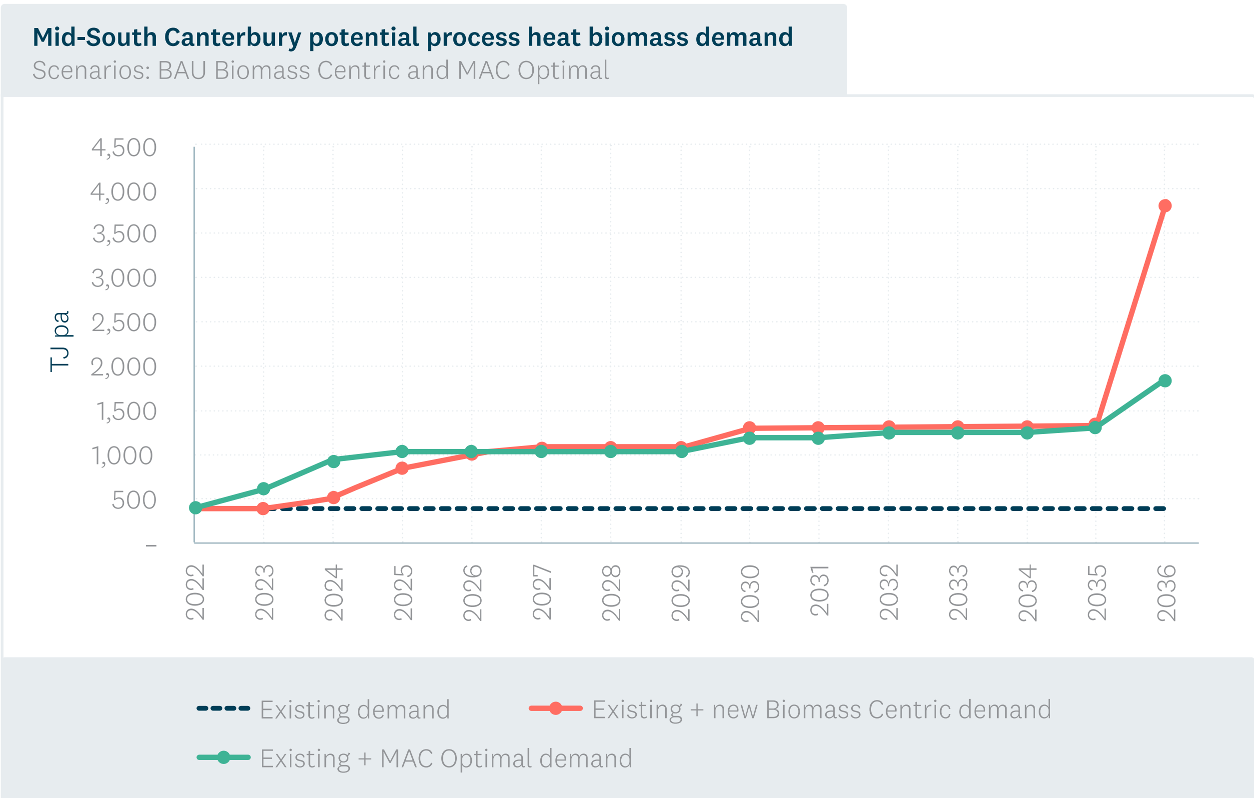
7.7.3 Scenarios of biomass costs to process heat users

With an emerging bioenergy market, there is no price history to draw on to calibrate price forecasts. To get an indication of what prices may be, we overlay plausible demand scenarios on each of the three supply curves above. These supply curves are based on a forecast of the costs of accessing these resources in 2022, with no additional margin applied, which is only intended to provide a proxy for potential future price scenarios.

These demand scenarios include the present consumption of bioenergy (~58,000 t pa), and assumes this continues throughout the 2023-2037 period.

Our demand curves through time (Figure 21) illustrate a scenario where biomass is selected as the fuel for every boiler conversion in the RETA study[46], i.e. it is a conservative forecast of biomass demand. The timing of each conversion (and when each increment will arise) is set by the dates in each organisation's ETA pathway, or, in the case where no date is set, 2036.

Figure 21 - Mid-South Canterbury region bioenergy demand for process heat, for 'Biomass Centric' pathway. Source: EECA



[46] Note committed switches to electricity are excluded.

Below we overlay the various increments in demand on the three supply curve periods.

Figure 22 - Biomass supply and demand, 2023-2027. Source: PF Olsen, EECA

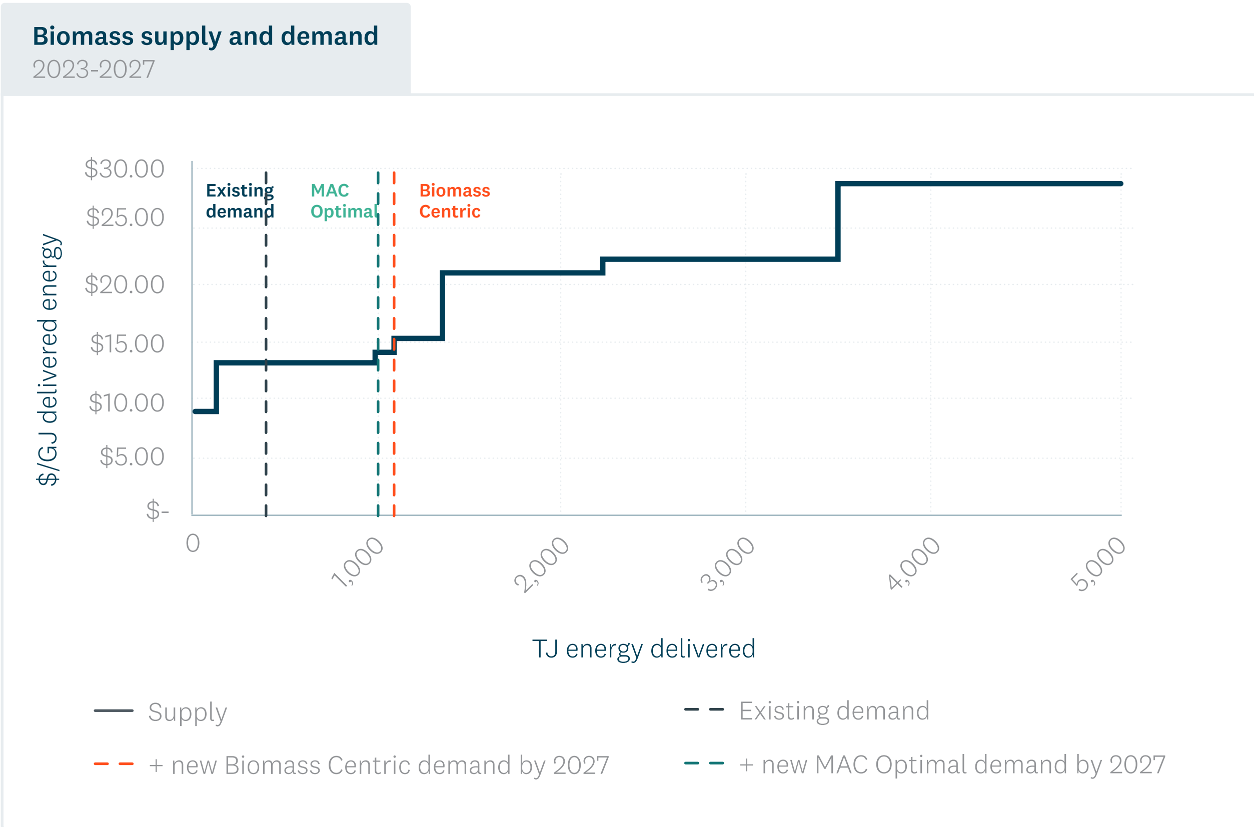


Figure 22 illustrates that both pathways see an increase in the use of biomass by over 200% compared to today, in a relatively short period of time. By the end of 2027, both pathways are fully utilising minor species, harvesting and processor residues, while a Biomass Centric pathway is beginning to use a small amount of wilding pines at a cost of around $15/GJ.

Figure 23 – Biomass supply and demand, 2028-2032. Source: PF Olsen, EECA

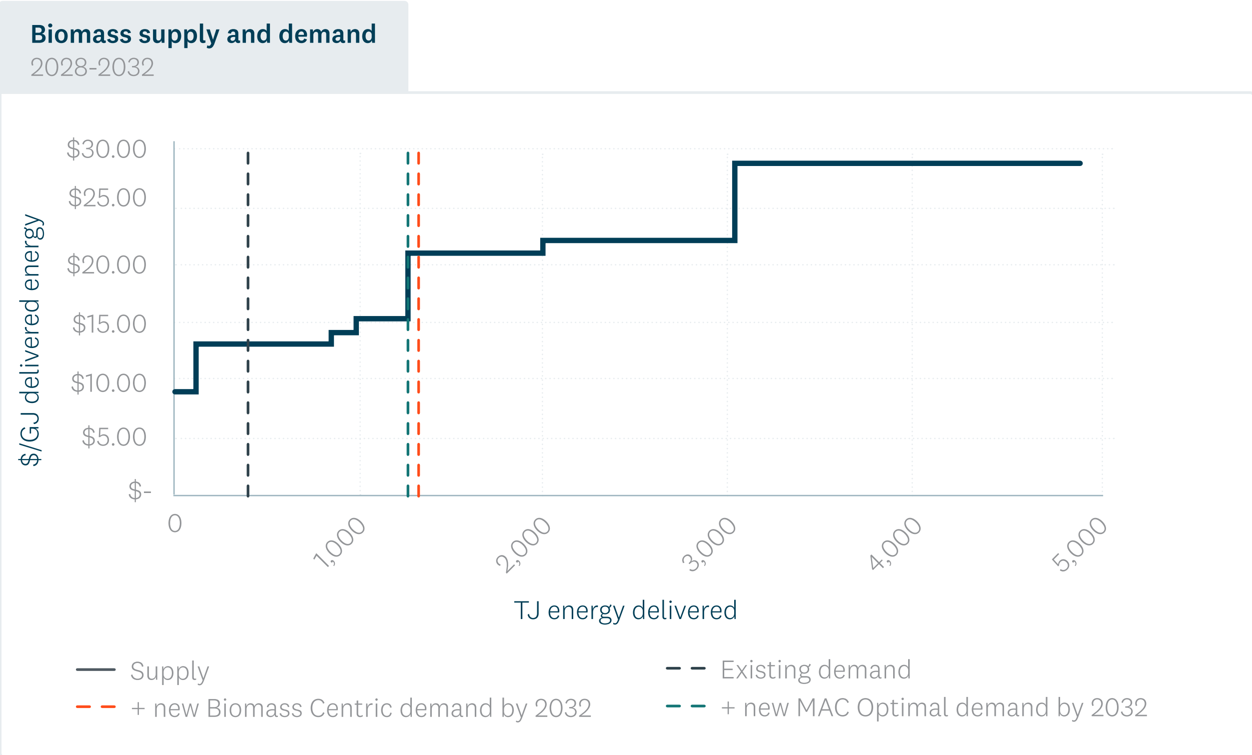
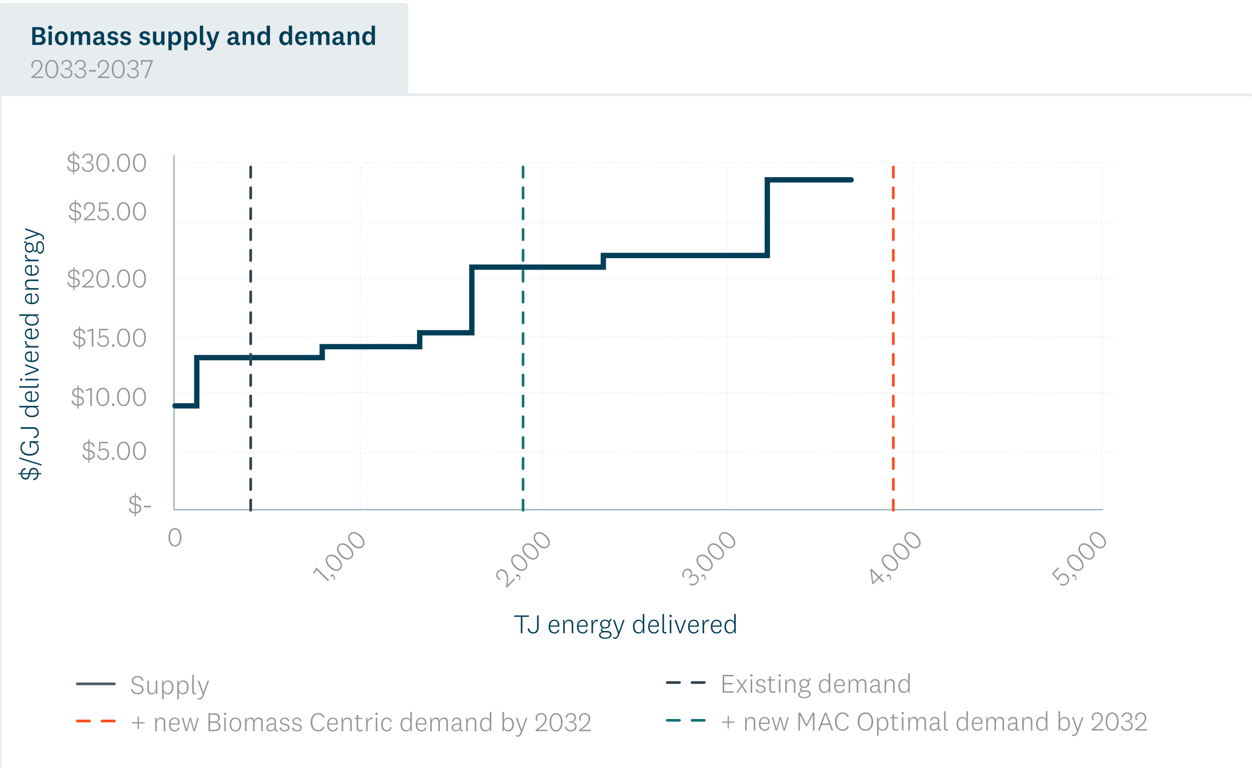


Figure 23 shows that both pathways have fully utilised residues and wilding pines. The Biomass Centric pathway is requiring the diversion of a small amount of low-grade Export K, KI and KIS logs.

Figure 24 – Biomass supply and demand, 2033-2037. Source: PF Olsen, EECA



In 2033-37, the MAC Optimal pathway is requiring ~200TJ low-grade export diversion, minor species, and a surplus of billet (over and above what is required to supply the domestic firewood market). Demand from the Biomass Centric pathway cannot be met by all the resources we have modelled, including higher grade export and domestic pruned resources (the latter which have reduced considerably in this five-year period).

The Biomass Centric pathway does not consider the economic rationality of biomass (compared to electricity), and is simply assuming all (unconfirmed) fuel switching decisions choose biomass irrespective of the cost of the fuel. Even beyond cost, we do not believe it is sensible to divert high grade logs[47] to biomass, especially on this scale. Hence the Biomass Centric pathway would likely require at least 1,400TJ (~200,000 t) of bioenergy-suitable woody biomass from other sources. The most obvious solution would be to import these from neighbouring regions, should they have a surplus, noting this will include an additional transport component.

There are a range of factors which may lead to the MAC Optimal pathway needing to consider neighbouring resources. As discussed above, the practicalities and costs of recovering cutover residues on steep hill country needs to be assessed more fully. Further, the domestic firewood market may expand to absorb some of the increase in billet wood that we are assuming is available to process heat. If this resulted in a downgrade of our assessment of resources, even the MAC Optimal pathway may exhaust the diversion of low-grade export logs.

[47] i.e. the last two steps on the supply curves, which are Export A and domestic pruned.

Port Blakely - Waimate, Canterbury, New Zealand

8 Electricity supply and infrastructure

This section considers the impact of the electrification of process heat on the electricity system.

The availability of electricity generation to meet the demand from process heat users is largely determined at a national 'wholesale' level, from a network of power stations around the country. This supply is transported to an individual RETA site through electricity networks - a transmission 'state highway' grid owned by Transpower, and a distribution 'local roads' network, owned by EDBs, that connects individual consumers to the boundary of Transpower's grid. The points on the grid where EDBs networks (and potentially some large consumers, such as Fonterra) interface with Transpower's grid are often referred to as Grid Exit Points, or GXPs.

Unlike biomass, where markets for the supply and delivery of wood for bioenergy are only starting to emerge, the electricity industry evolved a market and set of institutional arrangements in the 1990s to govern how competing supply resources meet energy demand. These arrangements and rules have led to a range of market participants who compete to provide generation, and to provide a variety of commercial arrangements for the supply of electricity to consumers. These institutional arrangements include a framework embedded in legislation that governs the activities of monopoly transmission and distribution networks. Overall, these arrangements strongly influence (and often constrain) how prices are calculated, revenue earned, and assets that are invested in (including timing).

Transpower and the EDBs are experiencing an increasing need for investment because of continued population and business growth, distributed generation, and the electrification of transport and process heat. While this RETA analysis only examines demand from process heat electrification, and public electric vehicle (EV) charging facilities where this information is available to EECA, this broader context of potentially rapid growth in demand is important to understanding the challenges associated with accommodating new load.

Electrification of process heat often leads to significant increases in demands on local electricity networks. Networks are primarily concerned with any increase in the highest level of instantaneous electricity demand – known as 'peak demand'. This is what EDBs design their networks to cope with.

The wholesale electricity market is designed to ensure that supply of electricity matches the demand for electricity in every instance. Moreover, the market is designed to incentivise owners of generation to invest in new power stations when demand increases – for example, as a result of the electrification of process heat. As long as the electricity transmission network is relatively unconstrained, this generation investment can occur anywhere in the country, and be delivered to the new sources of demand.

While the national wholesale electricity market will invariably ensure there is enough supply to meet demand at every point in time (at a price), transmission of power can be a challenge. In some cases, increases in electricity demand will be beyond the existing capability of the local distribution network, and possibly beyond the capacity of Transpower's high-voltage transmission network.

The primary considerations for a process heat user considering electrification are:

- What the price of electricity is likely to be, that pays to produce electricity to match demand, as well as pay for the use of existing electricity networks owned by Transpower and EDBs, and any other costs involved in consuming electricity[48].
- Whether the existing capacity in Transpower and the EDBs' networks[49] is sufficient to transport wholesale generation to their electricity-based process heat location at all points in time.
- If the networks do not have sufficient spare capacity, what is the cost, and ability of network companies' ability to deliver, any upgrades required to accommodate the peak electricity demand of process heat user (as well as any other consumers looking to increase electricity demand in that part of the network).
- The extent to which a process heat user can use any inherent flexibility in their consumption (the ability to reduce or interrupt demand at short notice, or to periodically shift demand from one time of the day to another) to reduce the cost of upgrades or wholesale generation.

This section covers these four topics.

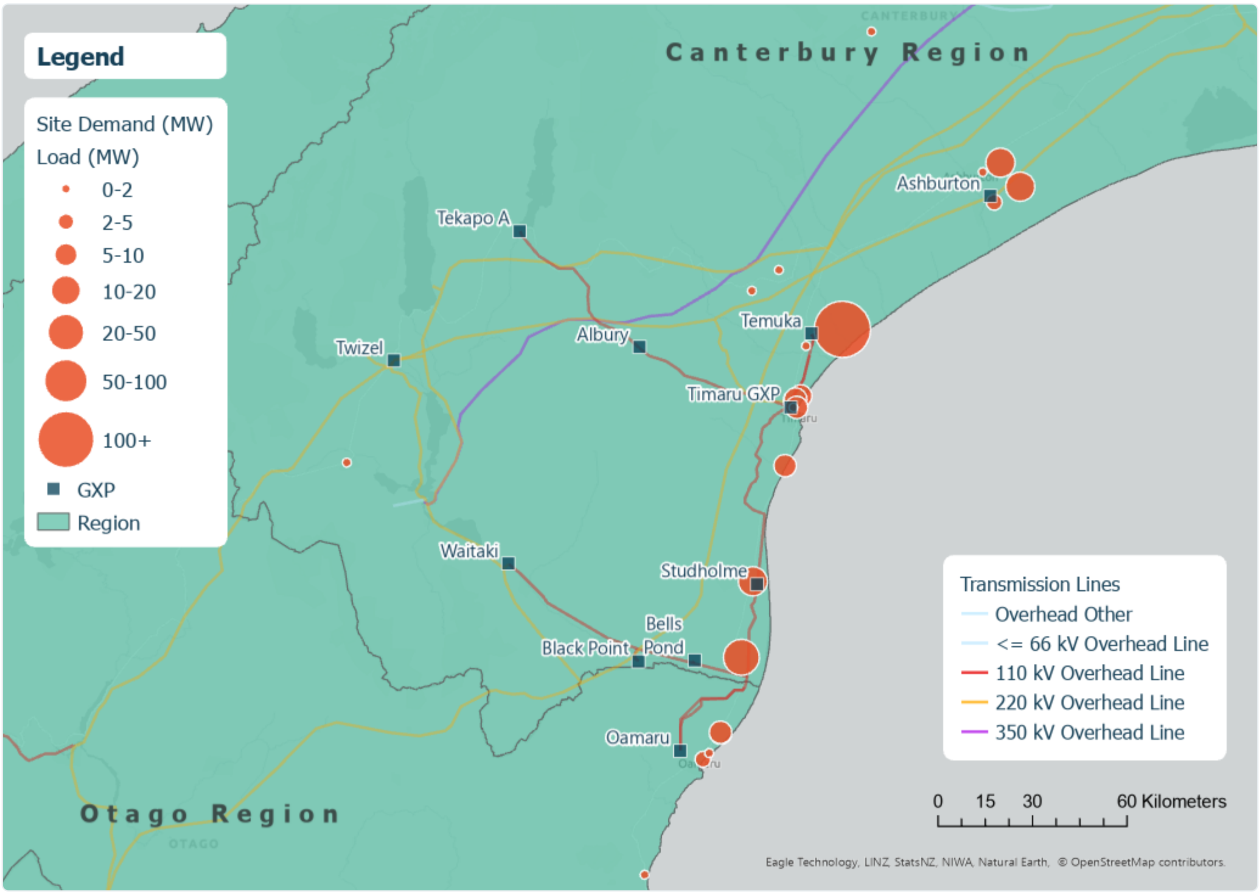
[48] As explained below, this includes metering, regulatory levies and other costs which consumers pay for.

[49] The site's spare capacity also must be considered, of course.

8.1 Overview of the Mid-South Canterbury electricity network

Figure 25 below shows the region's high-voltage grid (owned by Transpower), including the 11 GXPs where local EDBs take supply from the national grid. The 19 RETA sites considering electrification of process heat (see Table 4), plus three EV charging stations, are also displayed. Each connect to one of these EDB networks, noting that some (e.g. Oceania Dairy and Fonterra) connect very close to the GXP itself, due to their size.

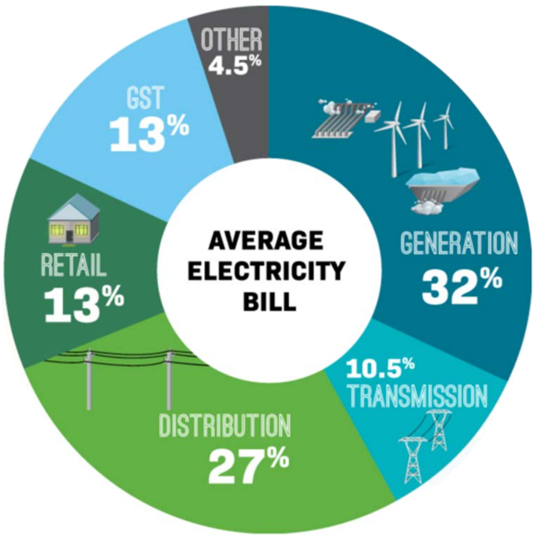
Figure 25 - Map of Mid-South Canterbury transmission grid, location and peak demand of RETA sites.



8.2 Retail electricity prices

Retail electricity prices, that would be faced by most of the sites[50], are a reflection of the average wholesale cost of electricity plus the network charges levied by EDBs and Transpower for the use of the existing network. The Electricity Authority publishes the image below showing how the total cost of electricity to a residential household is broken down:

Figure 26 - Components of the bill for a residential consumer. Source: Electricity Authority



However, while all of the components in Figure 26 are also present for large commercial and most industrial consumers, the breakdown will be different, and can vary substantially depending on the size of the facility (in terms of electricity demand), its proximity to a GXP, and its location in the country.

Given the complexity of the methodologies that determine the charges paid by non-residential consumers, it is difficult to generalise the likely magnitude of each of the components shown in Figure 26 above. This section provides general guidance on the generation, retail, distribution, and transmission components[51], but it is important that process heat users considering electrification engage with electricity retailers and EDBs to obtain tailored estimates relevant to their project.

[50] Again, unless the site connects directly to Transpower's network, in which case it may not use a retailer to interpose between the wholesale market and its purchases. Also, some users may request a 'wholesale' or 'spot' rate from their retailer, where the retailer passes through the half-hourly wholesale price (plus a margin). While this is almost exactly like being a grid connected customer, we consider it a retail arrangement here, due to the potential for margins or re-packaging of network charges by the retailer.

[51] On top of this, process heat sites will also pay charges for metering and Electricity Authority levies ('other' in the chart above).

8.2.1 Generation (or 'wholesale') prices

The generation or 'wholesale' cost of electricity is the result of electricity prices that arise from a market that clears supply and demand every half hour of the year. In order to derive a forecast of future retail electricity prices that can be used to assess the economics of electrification projects, ideally New Zealand needs a model that reflects the likely interaction of supply and demand, and therefore prices, in the wholesale market.

EECA engaged EnergyLink, an electricity market modelling firm, to use its sophisticated modelling of the electricity market to produce such a price forecast. EnergyLink's model simulates the interaction of wholesale electricity supply and demand, and thus produces wholesale market prices, in a way that closely resembles the mechanics of the actual half hourly market. This includes the way the New Zealand electricity market incorporates transmission losses into the wholesale price observed at each of the ~250 locations (GXPs or GIPs[52]) around the country where power is traded and reconciled. Finally, it also includes the impact of varying inflows into hydro reservoirs, which remains critical given New Zealand's reliance on hydro generation (~55% of total generation) will remain for some time yet[53].

However, to produce these prices over a multi-decadal timeframe, assumptions need to be formed about the future wholesale supply of, and demand for, electricity over this period. Given the significant uncertainty facing the electricity industry at the moment, EnergyLink developed three scenarios of supply and demand, including fuel costs, carbon costs and investment costs associated with new supply.

8.2.2 Retail prices

Most large users of power do not elect to face the half-hourly varying wholesale price, and instead prefer the stability of multi-year retail contracts that contain a 'schedule' of fixed prices, that each apply to different months, times of week and times of day[54]. Hence the three wholesale price scenarios were adjusted to reflect the observed difference between the wholesale price of power, and how large user retail contracts are typically priced. This is an approximation based on historical evidence but should be a plausible guide (based on trends) to what a customer should expect if it sought this type of retail contract. Each site contemplating electrification should engage with electricity retailers to obtain more refined estimates and potential options.

[52] Grid Exit Points (where electricity leaves the grid) and Grid Injection Points (where electricity enters the grid from power stations).

[53] There is some evidence from climate analyses that, at least on average, inflow patterns into the major hydro storage lakes (Lakes Tekapo and Pukaki, which represent ~70% of New Zealand's controllable storage) will change over the coming decades. The principal effect is that less precipitation will fall as snow as the globe warms, which has the effect of increasing winter inflows into these alpine lakes. EnergyLink have not included these effects in the scenarios produced for this project.

[54] Common contracts are often referred to as '144 part' contracts, reflecting the fact that the prices are specific to 12 months, two day types (weekday and other day) and six time periods within the day.

The retail electricity prices scenarios produced by EnergyLink are relevant to process heat users, reflecting what would be expected from a retailer that was pricing a large commercial contract. It is important to understand that:

- The EnergyLink price is only forecast for the generation and retail ('energy') component[55] of the customer's tariff, i.e. they do not include network charges (use of the existing transmission and distribution network, which is in addition to the costs of any upgrades considered above) which will vary from customer to customer. The network component of the bill is discussed further in Section 9.2.4 and 9.2.5.

- EnergyLink prices include the effects of high-voltage transmission losses to the nearest GXP in the Mid-South Canterbury region, but do not include distribution network losses to the customer's premises. Loss factors are set by EDBs companies to account for distribution losses, and these loss factors are applied by retailers to the GXP-based price. In the case of Mid-South Canterbury, losses for sites connecting at 11kV or 22kV typically range between 1.02 and 1.04, but in some situations (e.g. EA Networks) can be as high as 1.08[56].

- EnergyLink produce prices for four time 'blocks' each month – business day daytime, business day night-time, other day daytime and other day night-time. Different arrangements with a retailer may allow for different granularities of pricing and may also allow for the site to be rewarded for responding to e.g. high wholesale prices by shifting demand (see Section 9.5).

This is a relatively orthodox approach to modelling the electricity tariffs that process heat users may experience. However, some electricity retailers are evolving their tariffs to provide incentives for large process heat consumers to convert to electricity, and these tariffs have begun to emerge in the New Zealand industry[57]. As part of this RETA analysis, we have incorporated currently available special offers for process heat decarbonisation to be representative of retail prices for the first 10 years of a fuel switching project, after which we revert to EnergyLink's forecasts.

[55] This is generally the costs we have discussed above, relating to generation plus transmission losses and retailer margin, insofar as the latter is included in variable (c/kWh) charges. Some components of retailer margin may also be included in fixed daily charges from the retailer.

[56] EDBs publish network loss factors for different parts of the network, usually as part of their pricing schedule. An individual customer can find their loss factor by entering their ICP number (found on a recent power bill) in https://www.ea.govt.nz/consumers/your-power-data-in-your-hands/my-meter/ . The distribution loss factor for that site can then be found under the 'Network Pricing' section.

[57] For example, Meridian's process heat electrification programme pricing.

8.2.2.1 Scenarios considered

The three scenarios are characterised by assumptions that represent a 'Central' price scenario plus:

- **Low Price Scenario:** Assumptions that would lead to lower electricity prices compared with the Central scenario, through e.g. lower demand, lower fuel costs, or accelerated[58] build of new power stations.
- **High Price Scenario:** Assumptions that would lead to higher electricity prices than the Central scenario, e.g. higher demand, higher fuel costs or more restrained investment in new power stations.

The three scenarios used are outlined in Table 8 below. More detail on these assumptions is available in EnergyLink's report[59].

Table 8 - Electricity market scenarios considered. Source: EnergyLink

Scenario driver	Central Price Scenario	Low Price Scenario	High Price Scenario
NZAS at Tiwai Pt	Remains	Closes in 2025	Remains
Demand growth[60]	46TWh by 2032; 63TWh by 2048	As for Central scenario but ~5TWh lower from Tiwai exit	50TWh by 2032, 70TWh by 2048
Coal price	USD85/t	USD70/t	>USD100/t
Gas price	Medium	Low	High
Initial carbon price[61]	NZD75/t	NZD75/t	NZD75/t
Generation investment behaviour[62]	Neutral	Aggressive	Lagged/Conservative
Generation disinvestment	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2033	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037

[58] There is a limit to which the market will pursue accelerated or restrained investment – one would consistently suppress prices while the other consistently raise prices. This eventually has a feedback loop on other investors' intentions in terms of the profitability of their investment, and thus the timing of their investment (to the extent they can secure financing). However, we believe the degree of acceleration implied by EnergyLink's assumptions is plausible.

[59] EnergyLink (2022), 'Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Program', May 2022.

[60] EnergyLink did not provide sufficient data to perform a direct comparison, but their Low scenario appears slightly lower than the CCC's Demonstration Path (which included a Tiwai exit). EnergyLink's Central Estimate in 2032 looks ~3TWh lower than the CCC's 'Tiwai Stays' sensitivity.

[61] Note that the impact of the cost of carbon on the electricity price reduces over time as the electricity supply chain decarbonises and wholesale electricity prices become less sensitive to the cost of electricity generation that has a carbon component.

[62] Specifically, EnergyLink assume that a neutral approach would be an investor seeking to time construction such that target EBITDA is reached within two years of construction. A more aggressive approach would see investors build earlier (tolerating an undershoot of EBITDA by 10 percent), whereas a lagged approach would see investors delay construction to ensure 10 percent more than target EBITDA is achieved two years after construction.

EnergyLink also model the 'levelised cost of energy' (LCOE) associated with generation investment classes (e.g. wind, solar) into the future[63]. The degree to which these forecasts of LCOE affect investment are then a function of these costs, the way the projects are assumed to be financed, and the cost of debt.

Noting that the Low and High scenarios are not necessarily designed to be the most plausible storylines[64], but instead to apply assumptions that would deliberately lead to high and low price outcomes. As with many scenario analyses that involve mathematical models, there is a tendency for these models to understate the true range of potential prices as they cannot incorporate all of the real-world factors (including human decision making) that drive price. Thus, EnergyLink's scenarios provide information on what a range of price outcomes might look like. It is also important to note that the Low and High scenarios assume the variables in the table persist every year for 25 years. In reality, the market could periodically 'switch' from one scenario to another and remain there for a number of years.

The following assumption in EnergyLink's modelling are also relevant:

- The scenarios assume that the national electricity system reaches the Climate Change Commission's target of 95% renewable generation by 2030.
- The scenarios have not factored in the proposed pumped storage scheme at Lake Onslow. They do assume that the remaining thermal peaking plant can be switched (if deemed economic) to a low emissions fuel and has fuel storage large enough to support the system through extended periods of low inflows[65].
- EnergyLink apply different inflation assumptions to the various assumptions in the table above, each of which imply different rates of decline from its current level of 7% to a long-term rate of 2%.

[63] 'In real terms, the cost of building, owning, and operating new wind generation falls at rates calibrated against actual wind projects in New Zealand, with adjustments for the cost of financing projects. The cost of grid-scale solar farms also falls in real terms, but as there are no such projects in New Zealand, the rate at which costs fall is calculated from a combination of information that is in the public domain in New Zealand, along with data from overseas.' EnergyLink.

[64] For example, in the Low Scenario, Tiwai is assumed to exit but other decarbonisation demand is also assumed to be muted. However, it is the Tiwai exit scenario that is mostly likely to accelerate initiatives to decarbonise, not least because the price of electricity will be suppressed for quite some period of time, making electrification attractive.

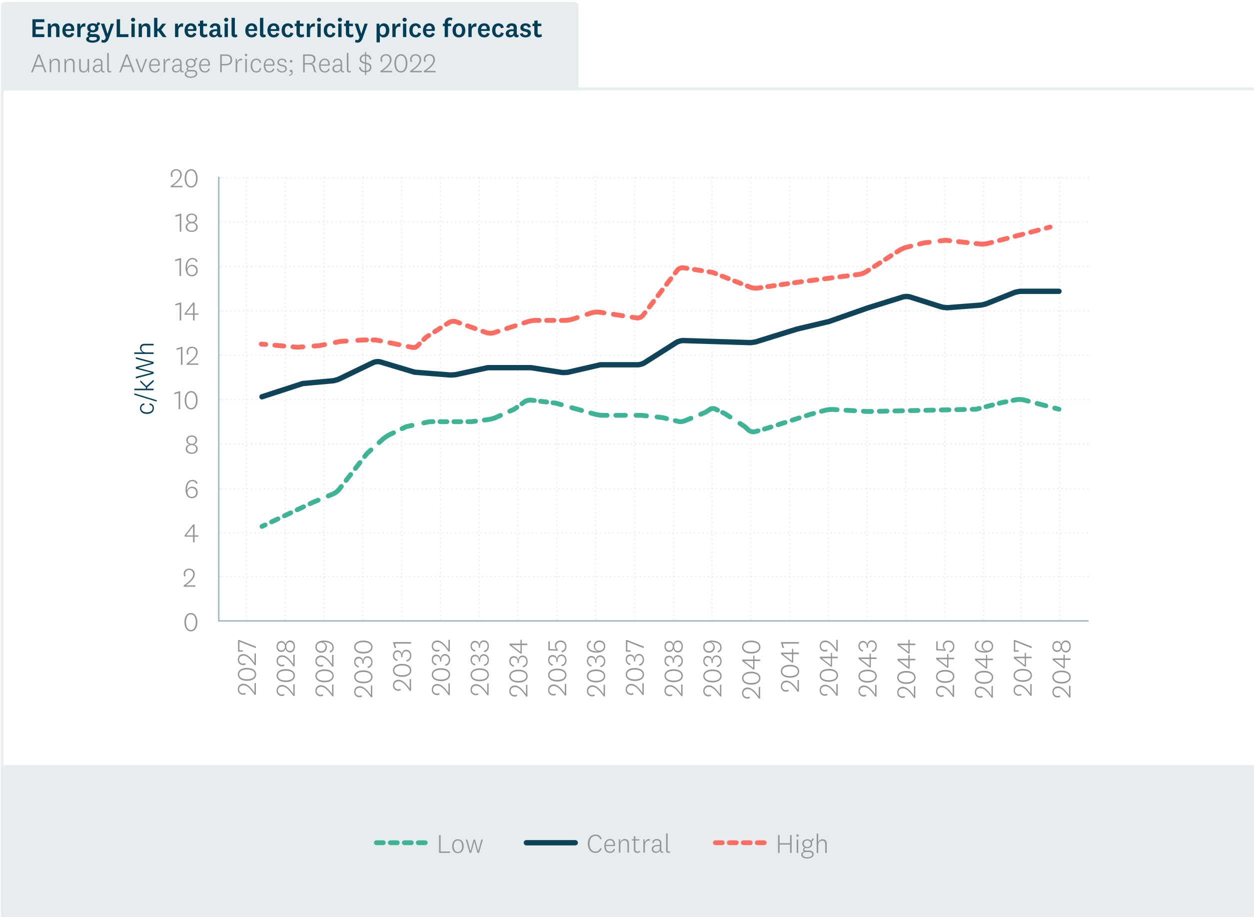
[65] Studies into future electricity supply are also considering the emergence of 'dunkelflaute' conditions, which are extended periods of cloud and low wind. These periods, potentially of weeks, such as that observed in continental Europe in 2021, would be beyond the capability of lithium-ion batteries and would also benefit from the presence of flexible generation such as peakers.

8.2.3 Price forecasts

Annual average (nominal) price forecasts are presented below for the period 2026-2048. In real terms, electricity prices remain at, or below recent levels indicated by EnergyLink's electricity contract price index until 2032 for the High scenario, and 2037 for the Low and Central scenario. After 2040 the Central and High scenarios see real prices exceeding that observed over the past 20 years, principally because of the impact of electrification of transport and process heat on electricity demand.

As is shown in Figure 27, the impact of Tiwai's exit (combined with the other assumptions in the Low scenario) significant. While this is a lower end on the range of prices, other forecasts (e.g. Climate Change Commission) show similar impacts from the Tiwai closure, albeit with shorter duration[66].

Figure 27 - Forecast of real annual average electricity price for large commercial and industrial demand. Source: EnergyLink



[66] The shorter duration of the price suppression in the CCC's modelling is likely to be due to the fact they did not combine a Tiwai exit with the other price-suppressing variables (e.g. low gas prices, lower decarbonisation demand, lower coal prices) in EnergyLink's modelling.

Beyond 2037, this forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond the end of the RETA period. Some New Zealand market analyses suggest real prices may remain constant after 2035, due to the downward pressure on generation costs (especially solar and wind) as technology and scale increases. Other analyses see continued increases. We cannot be definitive about electricity prices 20 years into the future and suggest business cases consider a range of scenarios.

As outlined earlier, the price forecasts are produced at a finer resolution than the annual average series in Figure 27. Figure 28 zooms in on 2030, showing (a) the variation over the year in the three scenarios, and (b) the variation between day type, and time of day.

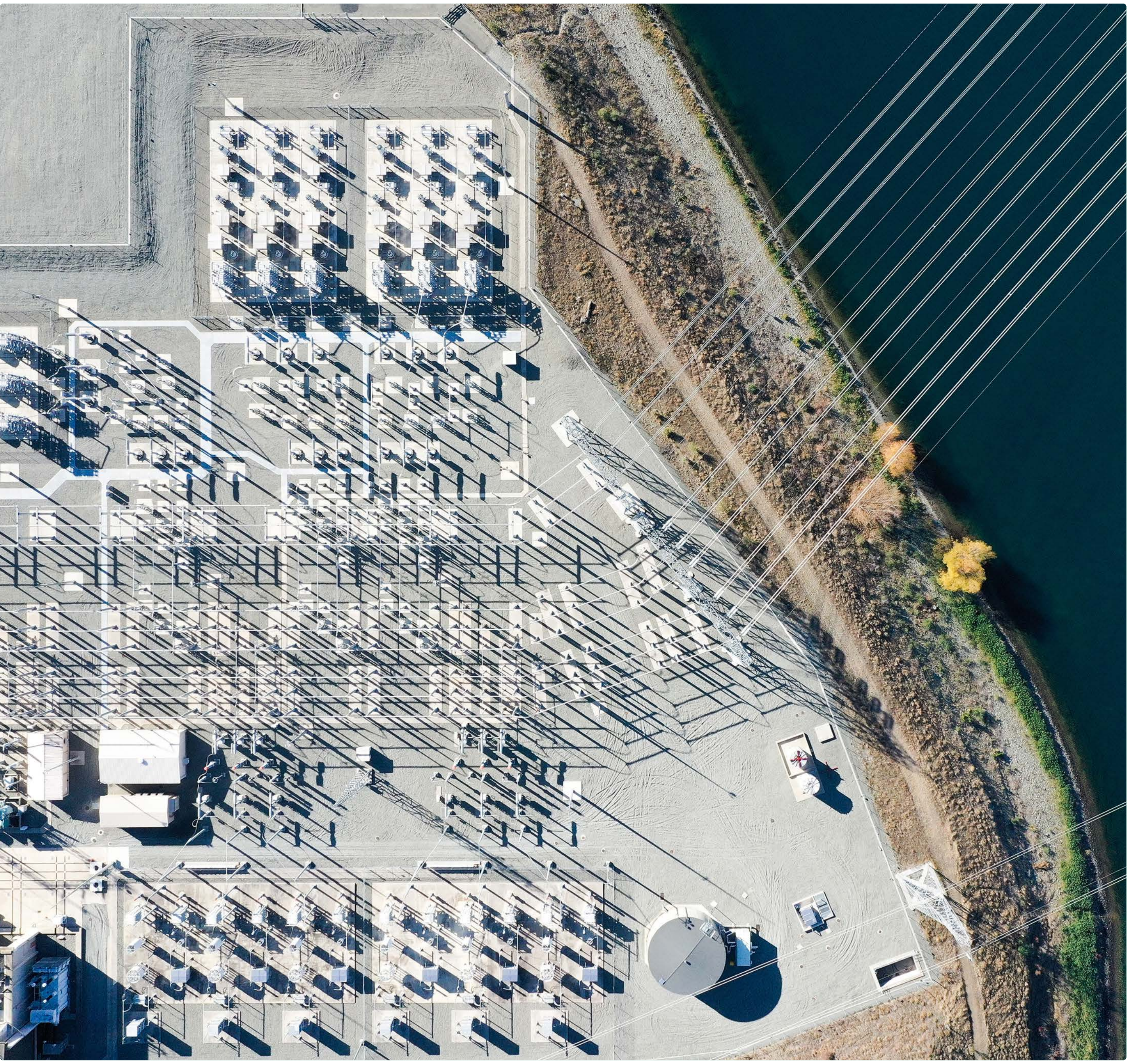
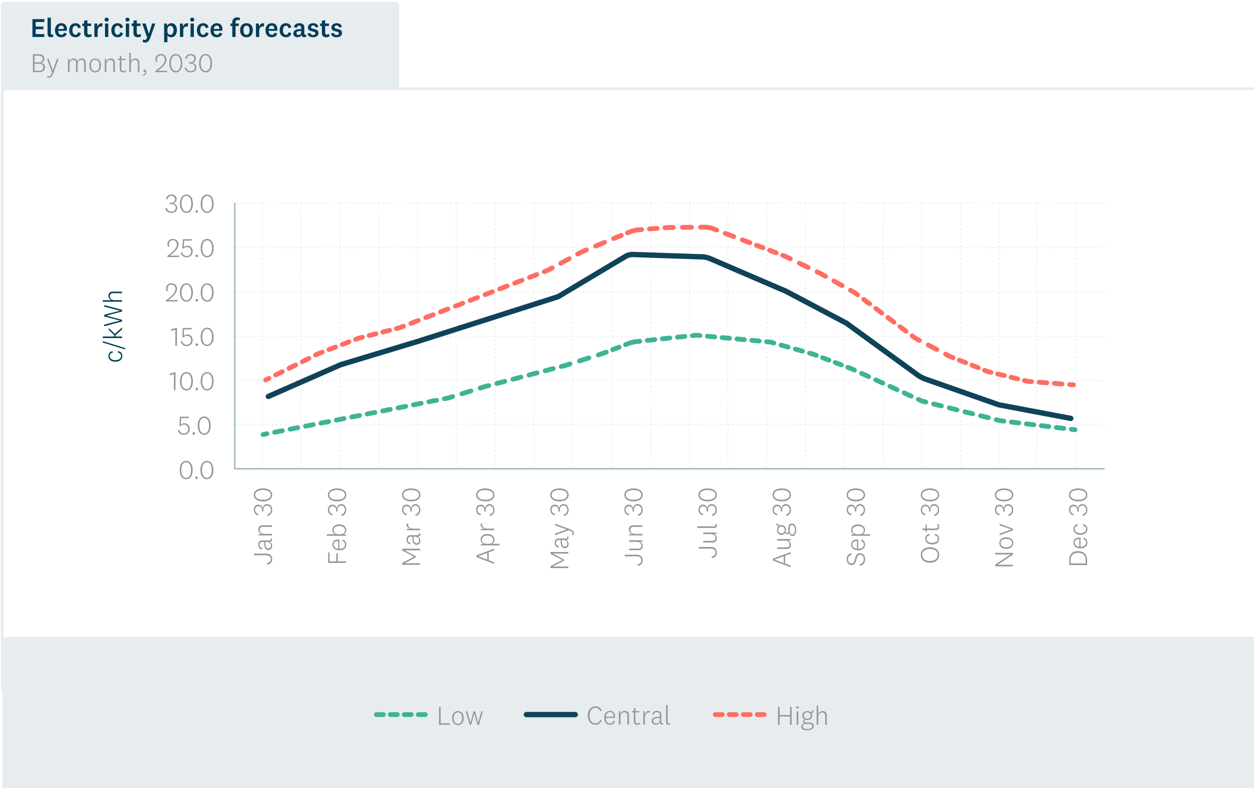
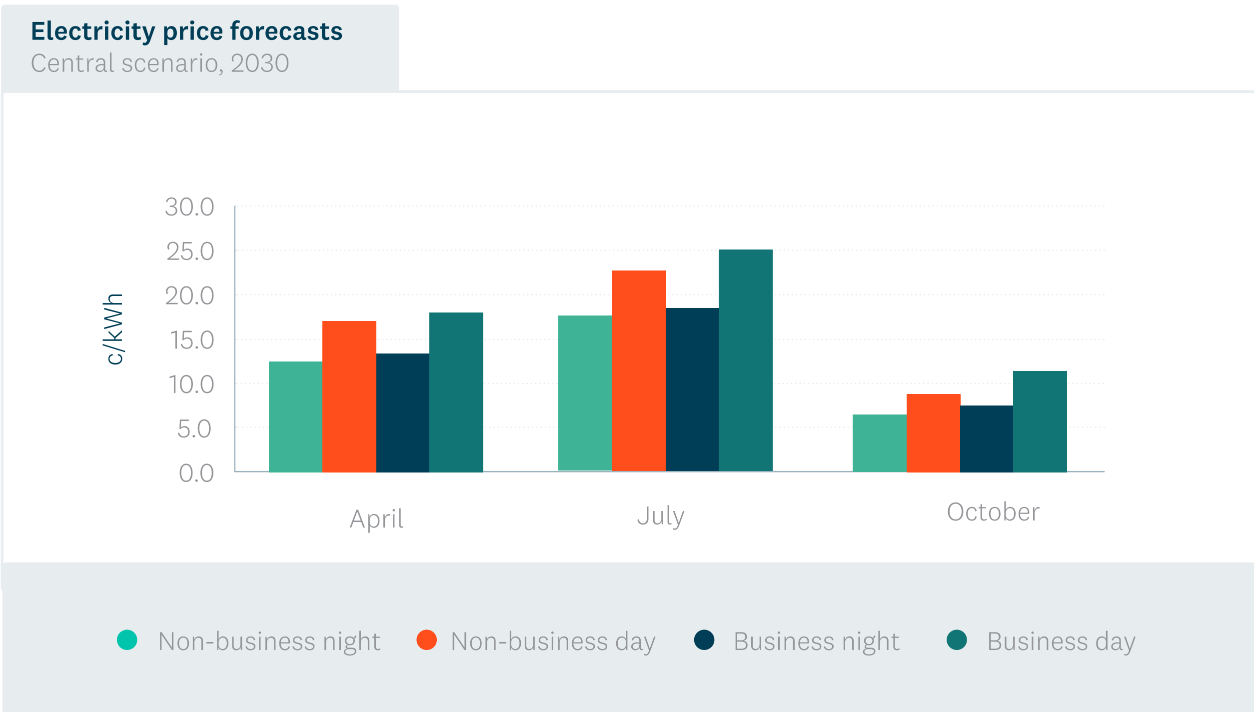


Figure 28 - Electricity price forecasts (a) by month and (b) by time block in April, July, and October 2030.
Source: EnergyLink





The shape of electricity prices over the year reflects the expected nature of national winter demand (winter peaking – lighting and heating) coupled with lower winter inflows into alpine lakes. However, this is somewhat inversely correlated with some of the sites considered in this study, particularly dairy, who experience the lowest levels of demand during winter. This means the volume-weighted price paid for electricity at these sites could be materially different from the annual average prices shown in Figure 27 above.

As noted above, the prices that a retailer will charge a process heat user will include the network loss factor discussed above (typically 1.02-1.04). EnergyLink's prices do not include this component.

8.2.4 Distribution network charges

EDBs levy charges on electricity customers for the use of the distribution network, except for those large customers who connect directly to one of Transpower's GXPs. As monopolies, EDBs are permitted under the Commerce Act to recover the cost of building and operating the distribution network plus a regulated return percentage. The total amount EDBs can earn is regulated by the Commerce Commission, while the way they charge (generally referred to as 'distribution pricing'[67]) is overseen by the Electricity Authority.

The magnitude of charges for any individual customer depends on each EDB's 'pricing methodology'[68]. This methodology describes how each EDB will convert its allowable revenue into prices for different customer groups, while meeting the principles set by the Electricity Authority for efficient pricing. Each year, these prices – for each customer group – are published by each EDB in a 'pricing schedule'[69].

Most businesses considering electrification of process heat would likely fall into a 'large customer', 'industrial' or medium voltage (11kV/22kV) category of charging for the three EDBs in Mid-South Canterbury. The four main factors used by these EDBs for pricing in these categories are:

- **i.** Daily fixed charges.
- **ii.** Volumetric charges (c/kWh, much like retail prices).
- **iii.** Demand charges (usually related to the highest level of demand reached by the site over a year[70], or the demand level during times when the whole network experiences its highest demand[71], usually measured in kW or MW).
- **iv.** Capacity charges (related to the full capacity of the connection provided by the EDB, measured in kVA or MVA).

[67] By this we mean how they allocate their costs amongst different customer groups, what variables they use to charge customers (e.g. capacity, peak demand, volumetric consumption) and other principle-based oversight. For more information see https://www.ea.govt.nz/operations/distribution/pricing/.

[68] The 2022-23 pricing methodologies for the three Mid-South Canterbury network companies can be found at: EA Networks, Alpine Energy, and Network Waitaki.

[69] The 2023 pricing schedules can be found here: EA Networks (2022), Alpine Energy (2022), Network Waitaki (2022)

[70] Often referred to as 'Anytime Maximum Demand', or AMD.

[71] Sometimes referred to as 'Coincident Peak Demand'.

While EDBs often use a combination of these factors for an individual customer, rarely would they use all. For large customers, it is typical to see (i) and (iii) and/or (iv) used. We note that Alpine Energy use (ii) for some large customers.

The specific pricing for a site will be agreed with the EDB concerned. However, for the modelling outlined in Section 11, we have developed indicative pricing for a generic large user inside each EDB area based on 2023/24 pricing schedules. These charges are shown in Table 9 below.

Table 9 – Estimated and normalised network charges for large industrial process heat consumers by EDB.

EDB	Fixed (pa)	Per MW/MVA (pa)
Alpine Energy	$1,047	$171,700
Network Waitaki	$960	$80,000
EA Networks	$1,708	$91,500
Average[72]	**$1,238**	**$114,710**

The charges in Table 9 above do not reflect the exact pricing structures each EDB uses – we have approximated the effect of different variables[73] in order to simplify the charges for the purposes of modelling. This also provides process heat users with an indicative magnitude of charges. The difference in prices between networks can reflect a variety of characteristics of each network – their pricing methodologies (which determines how costs are allocated between domestic, commercial, and industrial consumers), the nature of their network (e.g. proportion of high-density urban environments versus sparse rural areas) and where they are in their investment cycle.

[72] Note that the average is just a simple average and does not take account of the volumes of peak electricity demand that each network faces at these charges.

[73] For example, we estimated that demand from a process heat user has a 'load factor' (average demand divided by peak demand) of 0.45 in order to convert Alpine's volumetric charge into an annual per-MW equivalent. We also assumed that the process heat user reaches a peak demand equal to its KVA capacity.

While we provide these indicative levels of charges for process heat users, it is important that each business considering electrification of process heat engages with their EDB to discuss the exact pricing that would apply to them. When considering a business case for an investment that will last many years, a very important factor is the potential changes in how EDBs might structure their prices, and the degree to which these charges will be reflected in retail electricity contracts[74]. The Electricity Authority is working with EDBs to move their pricing approaches, over time, towards more efficient pricing structures, with five focus areas:

- Planning for future congestion.
- Avoiding first mover disadvantage for new/expanded connections.
- Transmission pricing pass-through (see below).
- Increased use of fixed charges.
- Not applying use-based charges (e.g. Anytime Maximum Demand) to recover fixed costs.

More detail is available on the Electricity Authority's website.

In addition to the *distribution* charges discussed above, EDBs also pass through Transpower's *transmission* charges. Usually, EDBs use the exact same variables (i) – (iv) above to add in this component, so that customers only see one aggregate price (or set of prices). While, generally, EDBs separate out the distribution and transmission component of network charges (in the interests of transparency), we have only included the distribution component here. The transmission component is discussed further in Section 9.2.5.

8.2.4.1 Contributions to the capital cost of accommodating new demand

In Section 9.3, we provide estimates of the capital costs that EDBs (and, for some large users, Transpower) would incur to upgrade their network to accommodate a particular process heat user's electrification decision. As outlined in Section 9.5, EDBs are also considering how they can use 'non-network solutions' – demand response from consumers, distribution-scale batteries, and distributed generation – to defer the need for more capital-intensive upgrades. As many of these solutions will be 'owned' by the consumer, the emerging world of network infrastructure investment is seeing a greater role for consumers than has historically been the case.

[74] Having these charges passed directly through to the process heat customer is only one way to incentivise flexibility. Since retailers ultimately way these charges to distributors, another way is for retailers to work with the process heat users to reduce demand at high price times, this reducing the retailer's costs, and share this benefit with the process heat users in any number of ways.

The charges in that section are presented as total capital costs. Precisely how the process heat user pays for these upgrades, however, is usually more complex than a simple up-front payment. There are a variety of ways that EDBs can recover these costs (assuming that it is the EDB that constructs the new assets[75]). These ways are presented in the EDB's 'capital contribution' policies. These policies recognise the fact that new demand is subject to the cost-recovery charges outlined above, and hence – over time – a component of the cost of new assets will be recovered through these charges. Hence the EDB may elect to calculate an up-front capital contribution that is only a portion of the total cost of the required upgrades. In some situations, the EDB may design customer-specific charges (often including a larger fixed component than indicated in Table 10 above), tailored to the process heat user's expected demand and location in the network[76].

The exact methodology used to determine the quantum of capital contribution it requires from new electricity demand varies between EDBs. It is important that process heat users contemplating electrification meet with their EDB to discuss how this will work in their situation.

8.2.5 Transmission network charges

Like EDBs, Transpower is permitted under the Commerce Act to earn a certain amount of revenue to cover the costs of owning and operating the national grid. Again, like EDBs, they are permitted to recover this revenue via charges on its customers for the use of the transmission grid, including any upgrades to the grid that might be required to accommodate increased demand on Transpower's grid assets.

Where a customer connects directly to the grid, Transpower will charge this customer directly. Otherwise, they are passed through[77] by the local EDB. This is a topic picked up further below.

The way in which Transpower (generally) charges its customers (distributors, directly connected industrials and generators) – known as the 'Transmission Pricing Methodology' (TPM) - has been a contentious topic since Transpower was separated from ECNZ in the early 1990s. Over the past 10 years, the Electricity Authority has conducted a number of phases of consultation in an effort to create a more enduring TPM, less subject to litigation.

A major revision to the TPM guidelines was concluded by the Electricity Authority in 2022. These charges come into effect for the 2023/24 pricing year[78]. This major revision includes guidelines for EDBs as to how to pass through the new transmission charges to their customers (which will include the majority of process heat users covered by this RETA)[79].

[75] In some situations, dedicated assets may be constructed by a third party.

[76] As an example, see EA Network's pricing for ANZCO Seafield, Talley's Fairfield, Mt Hutt and Highbank Pumps at EA Networks (2022).

[77] Without any markup by the EDB.

[78] A pricing year begins on 1st April for all network companies.

[79] We note that these guidelines did not include direction as to how EDBs or retailers present the transmission charges on the customer's bill. Thus process heat users (and any other customers) may not see any detail about what component of their new bills relates to the new transmission charges, although we expect distributors and retailers will want to explain any material increases in the overall bill.

The TPM is incredibly complex, and it is not possible to present the methodology in any detail here. But it is materially different from the TPM that has been in place for a number of years, which drives the current network prices that consumers see today. In order to help process heat users understand these changes, we provide below a commentary below on what the TPM is trying to achieve, and what that might mean for charges that are passed through by EDBs to process heat users.

8.2.5.1 Overview of the TPM

In essence, the TPM attempts to identify, amongst its customers (distributors, generators, direct connects), who the beneficiaries are of each of Transpower's assets, and allocate charges to those beneficiaries. This is a similar intent to the pricing methodologies of EDBs discussed in Section 9.2.4 above.

There are three basic components of the new TPM, plus a range of adjustments that are outlined further below. The three components are:

- **Connection charges:** There are some assets owned by Transpower which are only there for the benefit of a very small number of users. These are known as 'connection assets', as they tend to exist solely to connect an EDB's network, and/or a large industrial consumer, and/or a generator, to the national grid. In these situations, Transpower's costs - capital returns and operating expenses - are shared amongst that very small group of users in a relatively simple way.
- **Benefit-based charges (BBC):** These charges relate to specific investments where the beneficiary identification is more complex than for connection assets[80], but the beneficiaries have been established by the Authority (and allocations of charges calculated accordingly). This includes relatively recent grid upgrades that were approved by a regulator under the current market design, and were subject to a range of cost-benefit assessments. Should grid upgrades occur in the Mid-South Canterbury region (see Section 9.3), the associated transmission charges would be calculated in accordance with the BBC methodology. It is difficult to estimate at this point in time what the likely quantum of charges would be, as the Authority won't determine the allocations amongst the various beneficiaries until the investment is formally considered.
- **Residual charges:** For most of the existing transmission network it is either too speculative to identify specific beneficiaries of each asset, or the benefits are spread across so many customers, that a benefit-based approach is not used. These charges are referred to as the Residual Charge (RC) and are spread across all loads (EDBs and grid connected industrial consumers). Generators don't pay the RC. The RC is spread across loads in proportion to their anytime maximum demand.

  An important consideration for new grid-connected electricity demands, such as that arising from electrification of RETA process heat sites, is that they do not receive an RC charge for the first four years of operation; after that, the RC allocation steps up linearly over a four-year period. As a result, these new grid-connected demands do not face their full RC allocation for eight years.

[80] These more complex assets are referred to as 'interconnection assets', reflecting the fact that the tend to be part of the meshed grid, and the use of these assets can relate to a wide range of customers at different times. The residual charge also relates to interconnection assets.

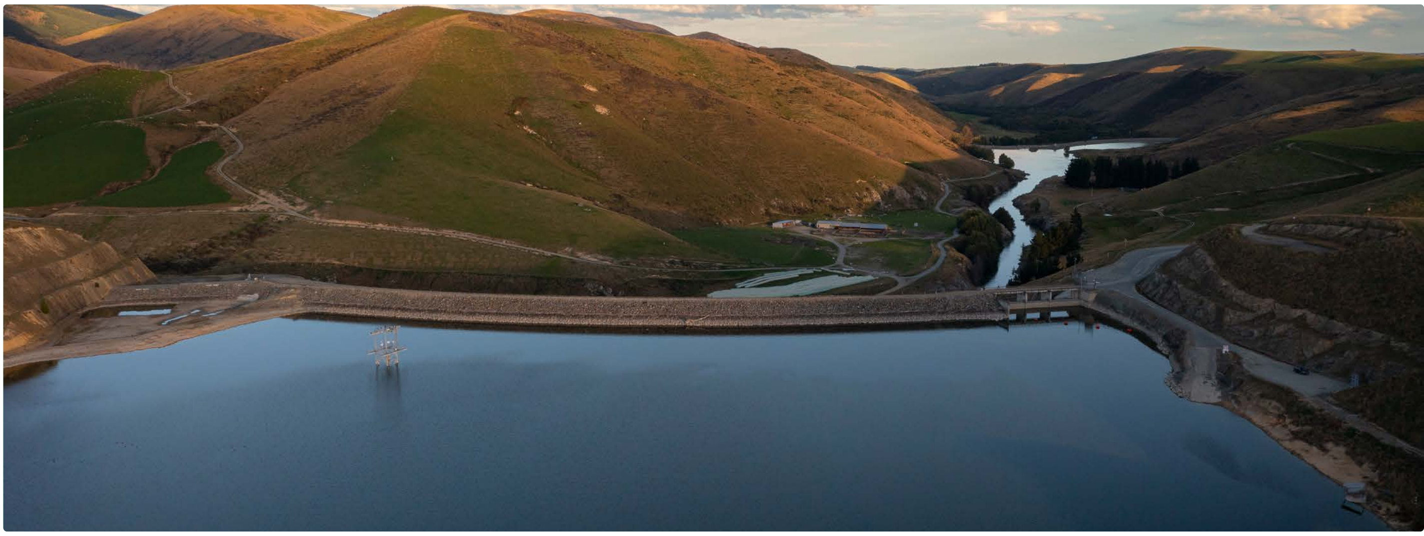
The intent and essence of the three types of charges may appear relatively straightforward, but the methods by which they will be determined (especially the BBC) is complex. To aid understanding, we have included a worked example for a stylised process heat consumer as Appendix 1 to this report.

Further, the Electricity Authority has included an additional set of mechanisms in the TPM that anticipate, and attempt to correct for, some undesirable outcomes that could occur with a customer's transmission charges. These include:

- **Transitional cap:** A transitional cap on prices to avoid 'rate shock'. The cap is inflation adjusted; hence, with prevailing rates of inflation in early 2023, the cap is unlikely to have any material effect on charges.
- **Adjustments to charges:** Adjustments for things like new connections to the transmission network, customers disconnecting from the transmission network, and substantial changes in circumstance leading to substantial changes in consumption (increased or decreased). This is especially important for the connection of new electrode boilers, which – as they are replacing coal – would in some cases lead to material increases in demand taken by EDBs from Transpower's grid. Equally, some large sites may decide, upon electrification, to switch from being connected to the distribution network to direct grid connection – this would cause a drop in the EDB's peak demand.
- **Prudent discounts:**

The EA will consider discounting transmission charges where, based on an economic framework, a customer is 'overcharged' as a result of the TPM.

Overcharging has a specific meaning, namely that the customer's TPM charges would lead them to inefficiently bypass the grid e.g. by building a self-supply and disconnecting from the grid or building a line to a different part of the grid. Transpower has published a draft prudent discount manual. There is a significant amount of analysis that is required to prove that an individual customer's TPM charges are a genuine case of 'overcharging'. We note that – since Transpower is entitled to recover a fixed amount of revenue from its customers – any reduction to one set of Transpower's customers, using the mechanisms above, results in an increase in charges to Transpower's other customers.



8.2.5.2 What does the TPM mean for RETA sites?

As noted above, our various references to 'customers' of Transpower, and thus payers of transmission charges, relate to EDBs, generators and grid connected industrial consumers. Most RETA participants do not fall into these categories, as they are connected to a local EDB's network, rather than Transpower's.

EDBs, however, will pass through transmission charges to their customers (i.e. electricity consumers). The exact mechanism by which each EDB 'repackages' TPM charges will vary across the country, but the Electricity Authority has published guidance on how they expect EDBs to do this.

Fundamentally, the Electricity Authority expects that an EDB will pass the TPM charges on consistently with how they are derived in the TPM:

- The BBC and RC to be passed on as a daily fixed charge.
- Connection charges will probably be on-charged substantially as done previously.

The EDBs will need to do some form of categorisation and averaging to allocate the transmission charges. The methods used in the TPM for categorising, averaging, and lagging measures of 'usage'[81] of the grid give a lot of discretion to how costs will fall. For example, an averaging method based on energy consumption will tend to move charges from residential towards industrial consumers and vice versa for averaging based on peak demand[82]. EDBs may also base charges on historical periods that, in their view, are a better reflection of the party's consumption that created the need for transmission capacity in the first place.

EDBs have published their pricing schedules for the 2023/24 pricing year – the first year that the new TPM applies. This provides distribution-connected RETA sites with an indication as to how significant the impact of the new TPM is on their charges (if EDBs have published the transmission component of the bill transparently)[83]. Based on 2023/24 disclosures from the Mid-South Canterbury EDBs that provide transparency of the transmission component, we have estimated that the transmission component of the bill is between $50,000-$80,000 per MW[84] of connection size, per annum.

However, even without any new grid investments, we strongly caution against using these figures as a guide. Transpower's indicative transmission charges for 2023/24 show that most charges accruing to EDBs are the residual charges. As outlined above, the intent of these charges is to recover the sunk costs of grid where individual beneficiaries cannot be identified. As such, they are intended to be fixed charges which should not change marginal operating or investment decisions. Defining these as per-MW charges accruing to newly electrified load may overstate their magnitude, depending on the degree to which EDBs rebalance charges across their customer bases.

[81] Either energy usage over time, or peak demand, for example.

[82] Residential demand tends to be more 'peaky' than many forms of non-residential demand.

[83] In their 2022/23 pricing schedules, only Alpine Energy and Network Waitaki separately reported the 'pass through' component of their prices. The majority of this component will relate to transmission charges calculated under the prior TPM.

[84] Alpine is at the lower end of this range, and Network Waitaki is at the upper end. EA Networks did not separate out their transmission component.

8.3 Impact of process heat electrification on network investment needs

EECA engaged Ergo to complete an assessment of the potential costs of transmission and distribution upgrades required to accommodate each individual RETA site, given the current capacity of the Mid-South Canterbury network. It is important to understand that this analysis was conducted to a level of accuracy commensurate with a 'screening' analysis and, necessarily, required Ergo to make a number of judgments and estimates. Each site contemplating electrification should engage with their EDB to obtain more refined estimates and potential options.

8.3.1 Non-process heat demand growth

The assessment of spare capacity at each point in the network is based on near term estimates of peak demand published by network companies, combined with knowledge of peak demand at each RETA site. Should some of the sites proceed to electrification, a number of years may pass between now and when the connection and fuel switch is finally commissioned. In this intervening period, some degree of demand growth (outside the sites considered in this RETA) will occur due to:

- Increased residential demand from new houses.
- Increased business demand from business growth and/or smaller scale fuel-switching away from fossil fuels.
- Increased transport demand from the electrification of private and public transport vehicles.

Where possible, we have included additional public EV charging stations, where EECA are aware of these.

Each individual EDB will have developed peak demand forecasts over the next 10+ years that account for these factors. EECA understands these forecasts are shared with Transpower, as they develop their peak demand forecasts for each GXP.

Depending on the magnitude of growth in electricity demand, some of the spare capacity identified may be absorbed by the time each site finalises its connection arrangements. Hence the above analysis is a snapshot in time and has not considered the degree to which future demand growth may change which investments 'trigger' an upgrade.

8.3.2 Network security levels – N and N-1

Before discussing the current state of the electricity network in Mid-South Canterbury, it is important to define the security standards that are used to define the capacity of the network.

While highly reliable, there is a small chance that components within electricity networks may fail. The conventional approach to maintaining supply to customers in a scenario of network failure is to consider the degree to which parts of the network have an in-built degree of redundancy in order to provide customers security of supply.

Like most infrastructure, electricity networks are sized to accommodate the very highest levels of expected demand ('peak demand'). In electricity, these peaks are very short in duration (a small number of hours per year) and often can occur at predictable times. Hence the overall level of 'secure capacity' is defined by the degree of redundancy that is available at peak times. At other times, more capacity is available. The level of secure capacity available to an individual site is a function of both:

- The available secure capacity at the point in time that the overall demand on the network reaches its highest level.
- The degree to which the site adds to that peak at the time it occurs (usually referred to as 'coincident demand').

Electricity networks use a convention to describe the level of connection security they provide all customers at a particular connection point. Broadly, this convention distinguishes two levels of security:

- **N-1 security:** Where N-1 security is present, forecast peak demand can be met and, furthermore, any 'credible' failure of a single component of the network (e.g. transformer or circuit) will also leave the system in a satisfactory state[85].
- **N security:** A failure of any single component of the network at forecast peak demand may result in service interruption.

N-1 is generally provided through building redundancy into network assets, relative to the expected (peak) demand. EECA is aware that some EDBs also use a concept of 'switched' security where the EDB responds to a network event by switching a customer across to an alternative network asset. This switching may result in a short interruption, which may or may not suit the customer. Alpine Energy refer to this as 'N-0.5'[86]. Presumably N-0.5 is a lower cost form of security (to the customer) than N-1, but EECA has not analysed this in any depth.

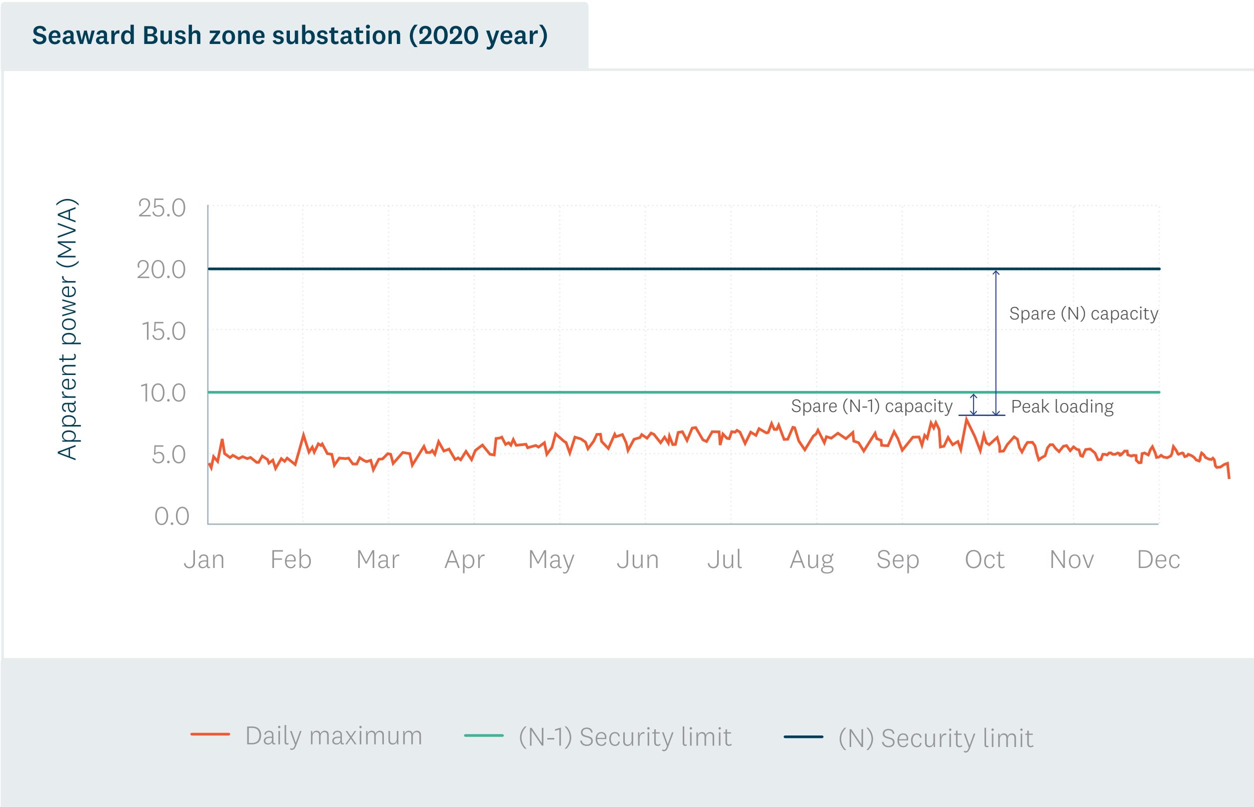
[85] This means that undue interruptions in supply or the spreading of a failure must not occur. Furthermore, the voltage must remain within the permitted limits and the remaining resources must not be overloaded.

[86] *'N-0.5 is the security level at which an outage will result in some load being able to be restored after ties have been made to other substations. Meaning the lost load will be partially restored (in this example 50 percent) after switching (reconfiguration of the network) and the remainder of the lost load will be restored in repair time.'* Alpine Energy (2023), Asset Management Plan 2023-2033, page 59.

Generally N-1 is the standard that applies on the 'interconnected' parts of Transpower's high-voltage transmission grid, due to the scale of bulk power flows affecting a large part of the population. However, on some more remote parts of Transpower's grid, the economic trade-off between N-1 and the cost to local consumers of the investment to accommodate demand growth may mean lower security is more efficient, and/or there are other ways to provide N-1 (see below) and better balance affordability. In the distribution networks, the lower scale, coupled with higher network density, means preserving N-1 to every customer would be exorbitantly expensive. Hence, many parts of the distribution network only experience N security. The extent to which an EDB provides (or preserves, in the face of increasing demand) N-1 is a risk-based assessment which considers, amongst other things, the proportion of time that a particular part of the network would exceed N-1 capacity.

Figure 29 illustrates the difference between the available capacity for N and N-1 security for a zone substation.

Figure 29 - Illustration of N and N-1 security capacity at Seaward Bush zone substation. Source: Ergo



For the purposes of this report, Ergo determined the amount of spare capacity by using Transpower's prudent peak demand forecast[87], rather than actual observed peak demand as inferred by Figure 28 above. The use of a prudent forecast recognises that there are a range of variables that can determine what happens on a given day or time, and when considering whether there is capacity available to accommodate a new process heat user, it is better to use a forecast.

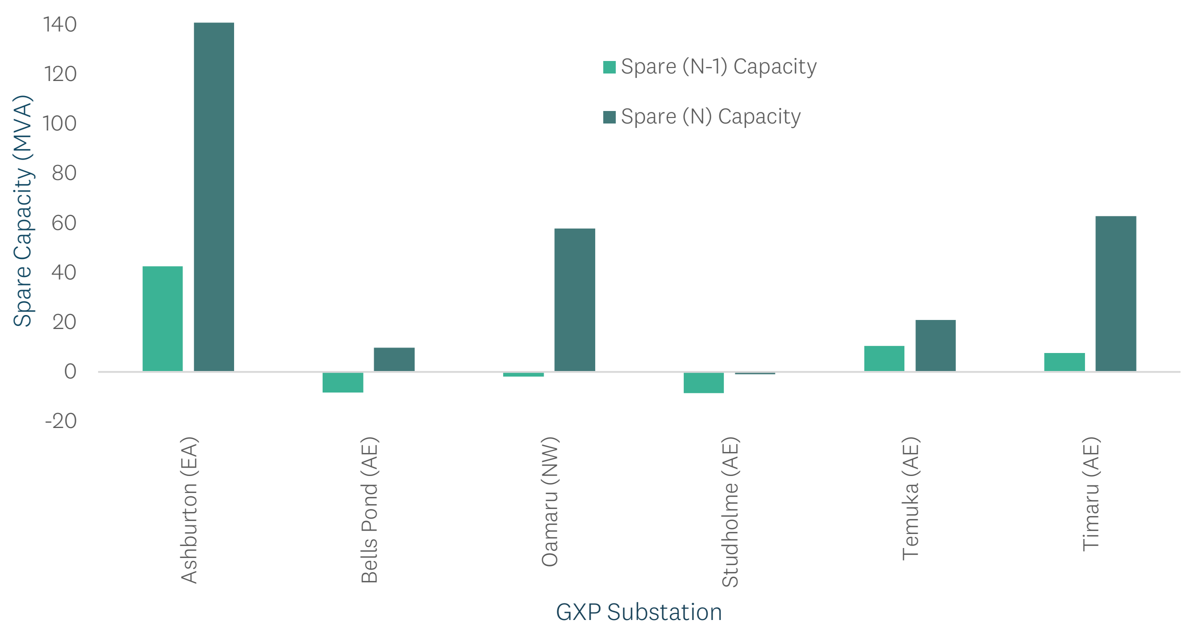
However, as discussed in Section 9.5, current spare capacity may be more efficiently utilized through new process heat users enabling flexibility in their production processes. Such flexibility can either be made available to network companies should a network failure occur (i.e. the '1' in N-1), or could be used systematically to avoid breaching the N-1 limit in real-time (through demand shifting).

8.3.3 Impact on transmission investment

The electrification of the RETA sites will increase the electricity demand Transpower will observe at six of the 11 GXPs. A number of these GXPs, and the connecting grid lines, have very little spare N-1 capacity remaining. This is summarised in Figure 30. For the avoidance of doubt, Figure 30 shows the capacity *headroom* at each GXP, i.e. the difference between Transpower's prudent demand forecast (for 2022) and the N or N-1 capacity at the GXP (as published by Transpower).

Figure 30 – Spare capacity at Transpower's Mid-South Canterbury grid exit points (GXPs). Source: Ergo

Spare capacity at Transpower's Mid-South Canterbury grid exit points (GXPs)



[87] Transpower's description of a prudent demand forecast is as follows: 'For the TPR we use a 'prudent' demand forecast to recognise the significant risks associated with investing too late to address grid issues. In effect, we add extra demand growth in the first seven years of the forecast to account for potential high levels of growth. After the first seven years we assume expected levels of growth. We determine the amount to add by calculating in our stage 1 models both the expected level of base demand and the 'prudent' 10 percent probability of exceedance base demand. The ratio of the stage 1 prudent base growth to expected base growth is then used to scale up the final demand from the stage 2 output to give the final 'prudent' forecast.' Transmission Planning Report (2022), page 20.

For those sites with limited spare capacity left, Transpower has planned upgrades. These are summarized in Table 10.

Table 10 – Spare grid exit point (GXP) capacity in Mid-South Canterbury and Transpower's currently planned grid upgrades.

GXP	EDB	RETA sites connected	Spare N-1 GXP capacity	Planned Transpower upgrade[88]
Ashburton	EA Networks	Talley's Ashburton Ashburton Meat Processors Canterbury Dried Fruits ANZCO Canterbury Mt Hutt Lime	Moderate	None
Bells Pond	Alpine	Oceania Dairy	None	Yes – New North Otago GXP ($35M); providing 120MVA N-1 capacity by 2033
Oamaru	Network Waitaki	Canterbury Spinners Oamaru Meats Alliance Pukeuri	None	Yes – Special protection scheme – New North Otago GXP ($35M)
Studholme	Alpine	Fonterra Studholme	None	Yes – remote switch and protection upgrade ($0.5M) Transformer replacement ($TBC)
Temuka	Alpine	Barkers Fruit Processing Ravensdown Lime, Geraldine Synlait, Talbot Forest Cheese Fonterra Clandeboye	Low	Yes – New (additional) 120MVA 110kV Transformer, 33kV switchboard and 110kV lines upgrade ($28M), or – New 220/33kV GXP at future Orari switching station ($TBC[89])
Timaru	Alpine	South Canterbury ByProducts McCain Foods Woolworks Washdyke Silver Fern Farms Paerora Alliance Smithfield	Low	Transpower discussing with Alpine upgrades to Timaru GXP. No costs provided are provided in Transpower's 2022 TPR[90]

[88] These are upgrades that are specifically contemplated by Transpower in their 2022 Transmission Planning Report (TPR)

[89] Transpower estimated $72M for Orari and Rangitata switching stations combined.

[90] Ergo estimated that a modest N-1 upgrade of the Timaru GXP may cost $16M. This cost is of the same engineering class (Class 5) as Ergo's other estimates.

We note that, alongside the transmission upgrades noted in the table above, a number of significant distribution upgrades are planned by EDBs which would also support the connection of process heat users.

Assessing the transmission grid implications of connecting RETA sites against current spare capacity is thus only part of the story – in many of the cases above where no spare capacity exists today, the planned upgrades in Table 10 will accommodate the connection of new electrified process heat users. Even at GXPs where there are no planned upgrades, the connection of multiple RETA process heat sites may be so significant that an upgrade is triggered. And finally, there may be some situations where there is insufficient spare N-1 capacity, but a process heat user may be able to either connect at N security – requiring it to be able to reduce demand should a contingency occur – or be able to reduce its demand at peak times to avoid breaching the existing N-1 limit. This is covered further in Section 9.5.

Table 10 shows there is potentially around $75M of grid upgrades, of direct relevance to RETA sites, already planned for the region. In the sections that follow, we note where the connection of an electrified process heat user will likely require one of these transmission grid upgrades (or one not contemplated in Table 10). However, we do not include any allocation of the costs of these wider upgrades to that user (except where the costs are specifically attributable to the process heat user). The allocation of costs for transmission upgrades is a complex topic, as discussed in Section 9.2.5 above.

8.3.4 Impact on EDB (distribution) investment

Most RETA sites will connect to the distribution (rather than transmission network). Here we present an analysis of whether the existing distribution network can accommodate each RETA site, and, if not, what the options are to upgrade the network sufficiently.

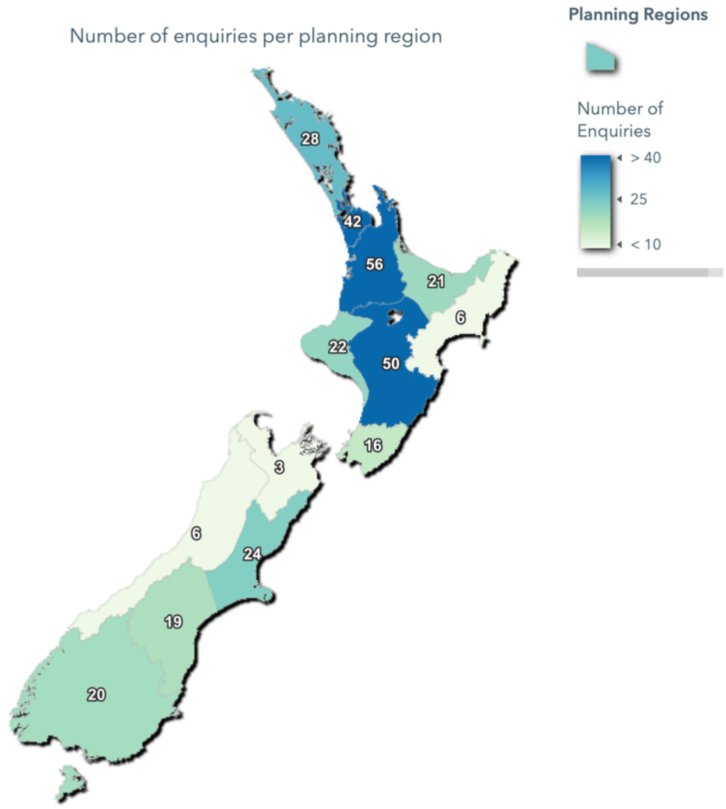
It is important to emphasise that the analysis undertaken here is preliminary and not intended as a detailed guide to the scope of works required to connect each site. The intended purpose is to provide a high-level 'screening' of process heat sites and the likely magnitude and complexity of their connection arrangements, should they choose to electrify. It is imperative that process heat owners seek more detailed assessments from the relevant EDB (and potentially Transpower) should they wish to investigate electrification further or develop more robust budgets[91].

We also stress that the information on which Ergo's assessments of spare network capacity, costs, and lead times is changing all the time. The policy and regulatory space for the electricity sector is in a state of change as it incorporates decarbonisation and the emergence of new technologies. This in turn is leading to a greater number of consumers considering the technology they buy and how they reduce their consumption of fossil fuels. Hence Transpower and EDBs exist in a context which is changing far more quickly than it did 20 years ago. Specifically, these organisations are experiencing a significant increase in requests from parties wanting to connect new generation or new load to their networks.

As an illustration of this, Figure 31 below shows the number of enquiries Transpower alone is facing in each of its planning regions. Of the 313 enquiries they face nationally, 77% have need dates prior to 2025. Transpower reports that of the 19 enquiries in South Canterbury alone, eight are for network upgrades (the remainder are for generation connections).

[91] Cost estimates have a Class 5 accuracy - suitable for concept screening. See https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

Figure 31 – Number of grid connection enquiries per region. Source: Transpower



EECA is aware that since the RETA commenced in the Mid-South Canterbury region, and the wider drive for decarbonisation of process heat and funding support, at least one EDB has received a significant number of enquiries regarding electrification of process heat. It is going to be challenging for EDBs to scale up their resourcing to cater to this new demand.

8.3.5 Analysis of individual RETA sites

Below we present the results of Ergo's analysis of the RETA sites in three sections, reflecting the potential connection complexity of each site:

- **Minor:** The 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Some connections may require infrastructure which takes additional time to procure from international suppliers or implement (e.g. transformers, underground cabling).
- **Moderate:** The 'as designed' electrical system requires some infrastructure upgrades including new connections into the local zone substation, upgrades at the local zone substation, and/or upgrades to the sub-transmission[92] network.
- **Major:** The 'as designed' electrical system requires large upgrades at both the transmission and distribution level, likely requiring substantial investment, potentially with lead times beyond 36 months.

[92] The network infrastructure which connects local zone substations to Transpower's GXP.

All estimates exclude the timeframes required for consenting and easements, if required. The categorisation of the projects does reflect the complexity of the potential work required and actual costs may differ from the indicative figures provided here. Also, since the assessment of upgrades required are limited to those that the process heat user would pay the EDB for directly (i.e. they are customer-initiated investments) there is no need for approval from the Commerce Commission. Were this not the case, the timelines for regulatory approval would need to be added to the timelines below.

Given the speed at which information is changing, the information presented below is indicative, and is a snapshot in time. Estimates are conservative. Each individual site should be re-considered when more detail is available.

In particular, the nature of information available at the time of this assessment, and the complexity of the task, necessitated a set of assumptions about how the various sites could be accommodated within the network. Exploring these assumptions with the relevant EDB may indicate where opportunities for cost reductions exist. Specifically, process heat users need to discuss the following aspects with EDBs and Transpower (where relevant):

- Confirm the spare capacities of both the GXP and Zone substations[93]. The analysis presented here calculated these based on the **publicly disclosed loading and capacity information** in Transpower's 2022 Transmission Planning Report and the EDBs 2022 Asset Management Plans.
- The degree to which the process heat user's demand is **coincident with peak demand on the network**, for the purposes of assessing the amount of spare capacity each site absorbs. More detailed modelling of the pattern of site demand, and potential flexibility in that pattern, versus the timing of (typical) peak loadings on the network, may yield further opportunities to reduce upgrade costs. Further, the opportunity for the site to provide short-term demand response (e.g. by utilising hot water storage to pause boiler operation for a small number of hours) in peak demand situations or following a network fault should be considered, as this may have a material impact on cost.
- **The current level of network security to the site, and whether that should be maintained.**
  The analysis below assumes that – for example - if the site currently presently has (N-1) security, infrastructure upgrades are recommended to maintain this. Ergo's report[94] highlights where upgrade costs could be reduced by allowing for a lower level of security. Adopting a lower level of security should be considered in consultation with Transpower and the EDB, but enabling the site to provide flexibility (i.e. rapid reduction) in demand in response to a failure on a network[95] could save significant amounts of money where expensive upgrades are required to maintain N-1 security.

93 Zone substations are large substations within the distribution network.

94 See Ergo (2023)

95 The most common way to do this is a 'Special Protection Scheme' whereby the network owner allows demand to exceed N-1 on the condition that, should a fault occur, demand is quickly (automatically) reduced to the N-1 limit.

- The extent to which the upgrades are affected by the decisions of **other process heat sites regarding electrification in a similar part of the network**. There are some parts of the transmission and distribution network where the collective effect of different upgrades and costs would be optimal should several sites simultaneously decide to electrify, or – more practically – coordinate their decisions in a way the gives the network owner confidence to invest. In Section 9.4, we highlight the situation in Timaru, where there is sufficient substation capacity at the GXP to accommodate any of the individual sites that would connect to the local network there. However, if a number of the sites chose to electrify their process heat, a GXP substation upgrade would potentially be required.
- The costs associated with **land purchase, easements and consenting for any network upgrades**. These costs are difficult to estimate without undertaking a detailed review of the available land (including a site visit) and the local council rules in relation to electrical infrastructure. For example, the upgrade of existing overhead lines or new lines/cables across private land requires utilities to secure easements to protect their assets. Securing easements can be a very time consuming and costly process. For this reason, the estimates for new electrical circuits generally assume they are installed in road reserve and involve underground cables in urban locations and overhead lines in rural locations. Generally, 110kV and 220kV lines cannot be installed in road reserve due to width requirements. In some locations the width of the road reserve is such that some lines cannot be installed. This issue only becomes transparent after a preliminary line design has been undertaken.
- The estimates of the **time required to execute the network upgrades**. The estimates below exclude any allowance for consenting and landowner negotiations and are based on Ergo's experience. There is likely to be significant variance depending on the scope of the project and the appetite for expediting.

The cost estimates below only include the incumbent network operator's distribution/transmission equipment and do not include onsite equipment that may be required to supply each site (for example, switchboards/cables within the respective sites are not included).

It also should be reiterated that the assessments in the following three sections are for each site in isolation of any consideration of other related RETA sites, and the timing of load growth (both from RETA sites as well as the wider growth as discussed in Section 9.3.1. This theme is returned to in the next section.

Table 11 lists the connections that are categorized as 'minor' in nature.

Table 11 - Connection costs and lead times for minor complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak site demand (MW)	Total cost[96] ($M)	Timing
Talleys – Ashburton*	Ashburton	EA	14.0	$1.61	12-18 months
Ashburton Meat Processors	Ashburton	EA	1.0	$0.29	3-6 months
Canterbury Dried Foods	Ashburton	EA	2.3	$0.05	3-6 months
ANZCO Canterbury*	Ashburton	EA	10.1	$1.91	24-36 months
Mt Hutt Lime*	Ashburton	EA	1.7	$1.52	12-18 months
Canterbury Spinners	Oamaru	Network Waitaki	3.2	$1.30	12-18 months
Oamaru Meats	Oamaru	Network Waitaki	1.1	$0.00	N/A
Moeraki Charging Station (Option 1 - 1.5MW)	Oamaru	Network Waitaki	1.5	$0.62	6 months
Barkers Fruit Processing	Temuka	Alpine Energy	1.3	$1.13	12-18 months
Ravensdown Lime	Temuka	Alpine Energy	1.3	$1.17	12-18 months
Synlait Talbot Forest Cheese	Temuka	Alpine Energy	1.3	$0.75	12-18 months
South Canterbury By Products (Option 1 - 7MW)	Timaru	Alpine Energy	7.0[97]	$3.00	11-18 months
McCain Foods (Option 1 - 8MW)	Timaru	Alpine Energy	8.0	$1.80	18-24 months
Woolworks Washdyke	Timaru	Alpine Energy	9.0	Committed	n/a
Silver Fern Farms Pareora*	Timaru	Alpine Energy	7.9[98]	$0.24	18-24 months
Alliance Smithfield	Timaru	Alpine Energy	5.9	$0.95	18-24 months
Timaru Charging Station (Option 1 - 1.1MW)	Timaru	Alpine Energy	1.1[99]	$0.40	6 months
Omarama Charging Station (Option 1 - 1.5MW)	Twizel	Network Waitaki	1.5	$0.31	6 months

[96] We reiterate that these costs do not include costs associated with the installation of distribution transformers/switchgear on the site.

[97] Demand could be between 7.0MW to 8.5MW.

[98] The demand could be 6.5MW to 7.9MW

[99] Ergo investigated an initial charging station capacity of 1.1MW, as well as a full future capacity of 6.1MW.

We reiterate that none of the minor complexity connections – individually – require upgrades to the transmission network, which is one of the main factors that lead to them being categorised as minor. Below, we consider the impact on the need for more substantial upgrades should a number of these minor complexity, at an individual GXP, choose to electrify their process heat.

The lead-times for investment in Table 11 are longer than reported by Ergo in the Southland RETA report. This is primarily due to extended lead times being experienced for equipment (e.g. large transformers) that need to be procured internationally.

Some of the sites above have more than one option for connection, and this has implications for costs:

- Some sites have two levels of potential peak demand, which depends on the decision made by the site. These sites are the EV charging stations, South Canterbury By Products, and McCain Foods. Ergo costed both, but the table above only presents one size of installation.
- Ergo determined that some sites had multiple options for how they were connected to the network. Usually, this optionality related to the security of supply that the owners wanted to achieve from the distribution network. These are denoted in the table above with a '*', and a choice was made about which option to present in the table above (for the sake of simplicity)[100].

Table 12 lists the connections that are categorised as 'moderate'.

Table 12 - Connection costs and lead times for moderate complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak MW	Total Cost ($M)	Timing
Oceania Dairy Ltd (Option 4 - 110kV Supply)	Bells Pond	Alpine	26.1	$5.10	36-48 months
Alliance Pukeuri	Oamaru	Network Waitaki	8.8	$3.55	24-36 months
Fonterra Studholme	Studholme	Transpower	16.0	$3.10	36-48 months

[100] See the full Ergo report 'South Canterbury: Spare Network Capacity and Load Conversion Opportunity Assessment'

We make the following observations in respect of the sites:

- The assessment of Oceania Dairy Ltd (ODL) considers a range of connection options, which depend on the multiple boiler configuration chosen by the owners, as well as the desired security of the sub-transmission connection. The estimate presented here allows for the largest installation totalling 26MW and achieving N-1 security on the sub-transmission network. Should ODL accept N security at the sub-transmission level, Ergo's estimate of connection costs would be approximately half that presented in the table. This illustrates the tradeoff between security and cost, a topic we pick up in the section on flexibility below.
- The connection of ODL in this configuration, to achieve N-1 security, also attracts $1.2M of transmission connection costs as a result of an upgrade to the sub-transmission circuits that would ultimately connect ODL to the Bells Pond GXP. These costs would be directly attributable to ODL's connection (under this option) and are included. For the avoidance of doubt, these costs do not include any component of the wider transmission network upgrades that would be required to maintain N-1 security at Bells Pond GXP, that are outlined in Section 9.3.3.
- The connection of Fonterra Studholme is estimated to accelerate the replacement of Transpower's supply transformers at Studholme. These would be considered 'connection costs' and would be attributable directly to Fonterra (see Section 9.2.5). Hence the estimate of Fonterra Studholme's total connection costs include a $1M capital contribution to these transformers. Again, these estimates do not include any allocation of the costs required to upgrade the ability of the wider transmission network that would allow Studholme to maintain N-1 security with an increase in demand from Fonterra Studholme.

Table 13 lists the connections that are categorized as 'major'.

Table 13 - Connection costs and lead times for major complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak MW	Total Cost ($M)	Timing
Fonterra Clandeboye (Option 3 - heat pump and 4 boilers)	New	Alpine	90.5	$51.90	48-60 months

The categorisation and costs in Table 13 assumes Fonterra electrifies the entire Clandeboye site. We make the following observations:

- Ergo overlaid an estimated demand profile for the Fonterra Clandeboye site (under different configurations) on the current Temuka GXP demand to estimate the net demand increase that would result from the heat pump and boilers under consideration by Fonterra. This showed that – based on the assumed operating profile – the connection of a 7MW heat pump alone would only increase the peak demand at Temuka by 5.5MW. Similar results were obtained for the other boilers. This underscores the importance of this level of analysis – as a result of a diversity between the operating profiles of the process heat demands and the existing demand, the net increase in peak demand at a GXP may be less than the simple addition of the capacity of the new equipment.
- There is sufficient capacity in the Clandeboye 1[101] substation and the surrounding network to be able to supply the heat pump by itself (Option 1 in Table 14 below), noting this will increase the range of periods where the Temuka Special Protection Scheme would be 'active'[102]. However, the addition of any single boiler to the heat pump demand necessitates upgrades to the sub transmission and transmission network. Ergo developed two potential options for these upgrades (Options 2 and 3), which have minor differences in cost (well within the margin of error for a screening analysis).
- Should Fonterra electrify the entire site, both Option 2 and Option 3 accommodate all four boilers, and require a connection to the proposed new Orari switching station (see Section 9.3.3), although – again – does not include any costs associated with this new switching station (other than directly attributable connection costs).

Table 14 – Alternative connection configurations for Fonterra Clandeboye. Source: Ergo

Option	Additional connected load	Net impact on peak demand	Connection Security	Estimated Capital Cost ($M)
Fonterra Option 1 – heat pump and one boiler	36MW	32MW	N-1	$21.00
Fonterra Options 2 and 3 – four boilers and heat pump	103MW	91MW	N-1	$52.00-$53.00[103]

[101] The Fonterra Clandeboye plant is presently fed from two zone substations on the plant's site. These zone substations are named Clandeboye 1 and Clandeboye 2.

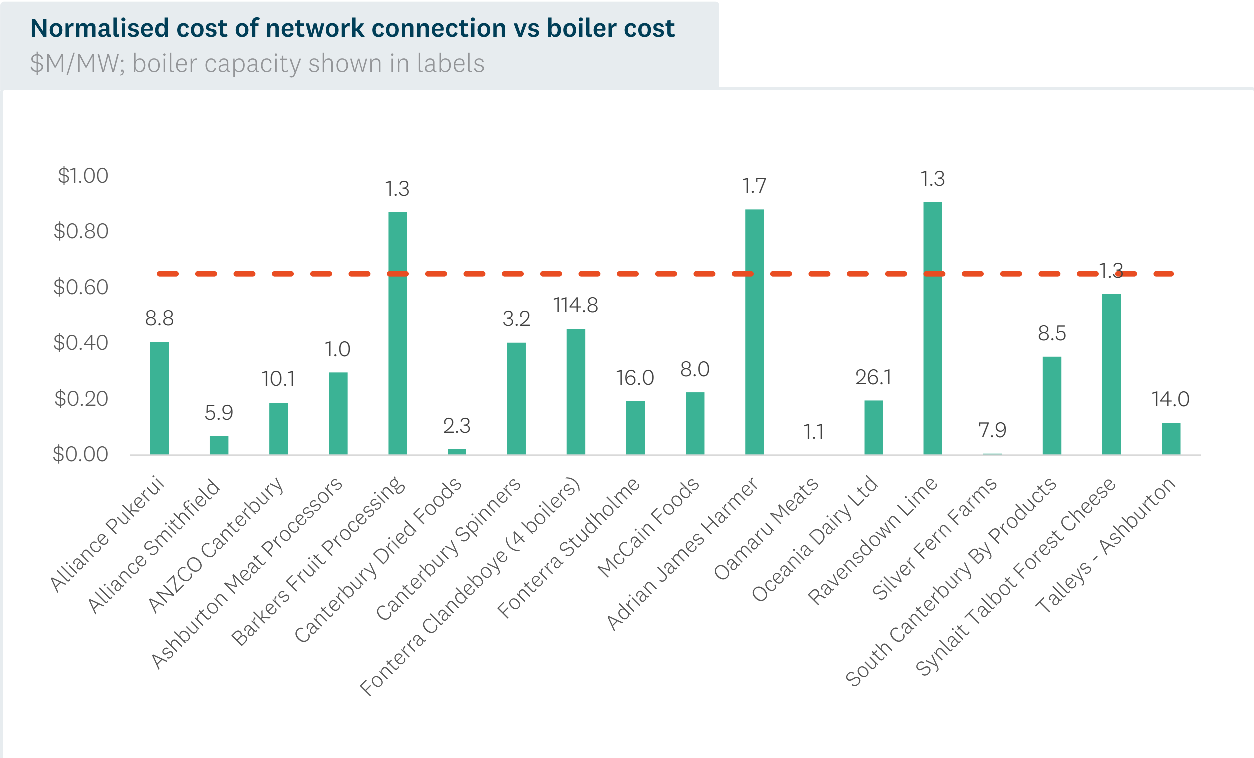
[102] As discussed above, Special Protection Schemes (SPS) allows demand to increase above the N-1 limit, on the basis that, should a network failure occur, a sufficient amount of customer load will be curtailed in order to bring demand back within the capability of the network. There is an SPS in place for Temuka; increasing demand generally means there are more periods where load will exceed the N-1 limit, and therefore a higher risk that the SPS will be activated by a network failure.

[103] The range in costs reflects Ergo's different options for how a heat pump and 4-boiler configuration could be achieved. See Ergo (2023), page 93-94

8.3.6 Summary

The network connection costs presented above vary significantly in magnitude. But it is worth viewing these costs through the lens of the size of the boiler installation. Figure 32 shows each site's connection costs expressed in per-MW terms, that is, relative to the capacity of the proposed boiler.

Figure 32 - Normalised cost of network connection vs boiler cost. Source: Ergo, EECA



The red dashed line in Figure 31 compares these per-MW costs to the estimated cost of an electrode boiler ($650,000 per MW[104]). The figure shows not only a wide variety of relative costs of connecting electrode boilers, but that for a number of the 18 connections, the connection cost is over half the cost of the boiler (i.e. increases the installation cost by at least 50%), and in three cases, more than doubles the capital cost. Finally, Figure 31 shows that the four highest $-per-MW cost of connection sites are among the smallest projects, and thus are not benefitting from the scale economies that comes from the larger sites.

While the estimates of connection costs provided here are of an accuracy commensurate with this screening analysis, it does demonstrate how connection costs can have a significant effect on the final decision. It also shows that, particularly for smaller electrification projects, reductions in connection cost of only $100,000 could have a significant effect on fuel switching decisions. We explored this sensitivity more in Section 11, when we use marginal abatement costs to simulate the optimal fuel choices.

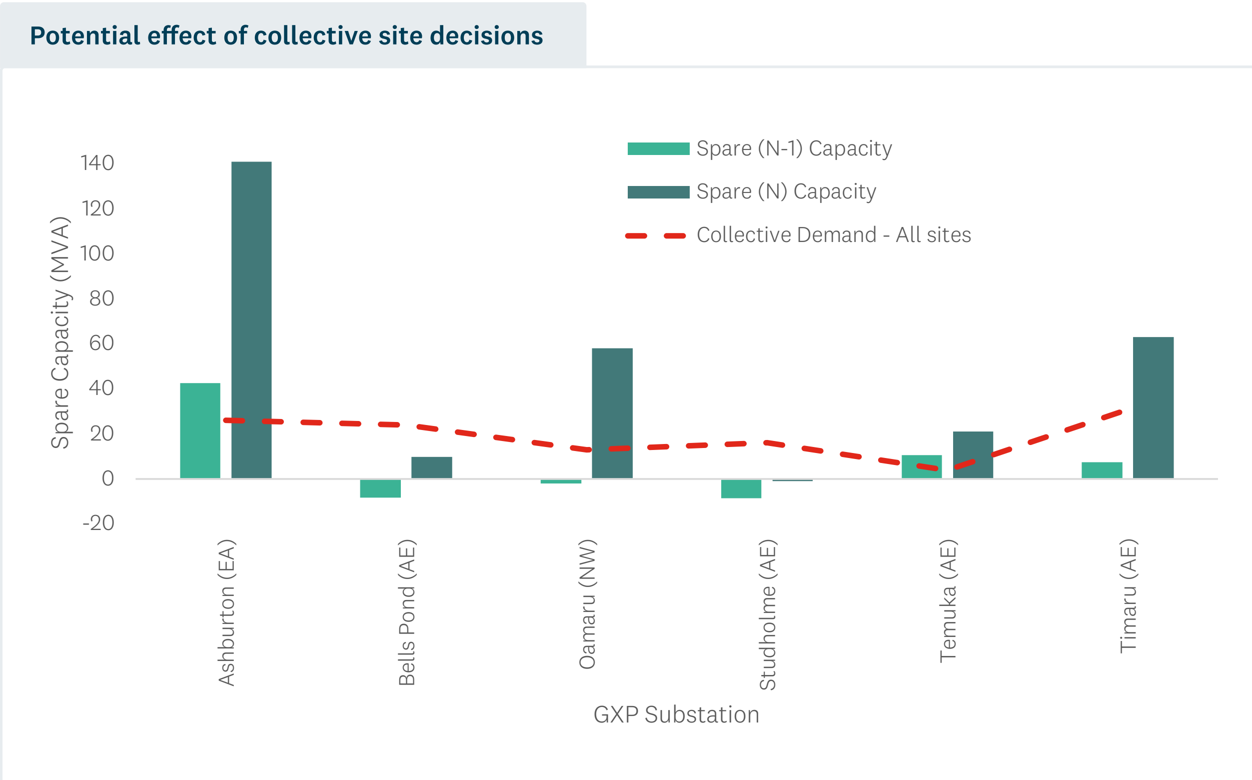
[104] This is the estimate used in the development of the marginal abatement costs and pathways presented in Section 10.

8.4 Collective impact on upgrade costs

The above analysis considered each site in isolation from each other, and whether it could fit into the spare capacity available at existing substations.

Here we consider what the impact would be on spare capacity at each GXP if all Mid-South Canterbury RETA sites chose to electrify (Figure 33).

Figure 33 – Potential combined effect of site decisions at each GXP. Source: Ergo



In Figure 32 we have taken the most conservative view of new demand from electrification, by assuming that:

- All RETA sites decide to electrify their process heat.
- Spare capacity is determined by comparing N and N-1 capacity today to Transpower's prudent demand forecast for 2023, rather than the actual peak demand observed in recent years.
- All RETA sites will reach their peak demand at the same point in time, and at the same time as existing demand at the GXP peaks; practically speaking, where there is a number of sites, diversity of sites and operational realities is likely to result in the combined peak being lower than this figure[105].
- It is assumed that none of the sites actively manage their demand to avoid system peaks; again, this is a conservative view of peak demand.

[105] Ergo's analysis considered and demonstrated the impact of load diversity in specific situations in MSC – e.g. Timaru.

The analysis highlights the fact that Bells Pond, Oamaru and Studholme all require upgrades to Transpower's assets in order to maintain current security levels at the GXP substation: This is true even if only one site at each of these GXPs electrified, since the GXP is not maintaining security at present, if demand is represented by Transpower's prudent peak demand forecast[106].

Should all RETA sites at Ashburton and Temuka connect, N-1 on the transmission network can be preserved, unless Fonterra chose to only electrify one boiler and add this demand to Temuka (rather than connect to a new switching station as outlined above).

At Timaru, however, there is only sufficient spare N-1 capacity (8MW) – based on Transpower's prudent forecast – to accommodate one of the individual RETA sites[107] (or two, if one of them is the first stage of the Timaru charging station):

- South Canterbury By Products (7.0MW).
- Woolworks Washdyke (9.0MW).
- Silver Fern Farms Pareora (7.9MW).
- Alliance Smithfield (5.9MW).
- Timaru Charging Station (1.1MW to 6.1MW).

But there are a number of combinations of individual sites that might trigger a need for an upgrade to the transmission network in order to preserve N-1, as shown in Figure 32. As outlined in Section 9.3.3, Transpower has commenced discussions with Alpine Energy to upgrade the Timaru GXP. However, no costs have yet been published for the various options. Ergo have estimated that a significant transmission upgrade at Timaru, sufficient to accommodate an additional 60MW of load, would cost $16M.

That said, Figure 33 assumed every site connecting to Timaru would reach its peak output at the same time as the Timaru GXP experienced its peak demand. This would add 31MW to peak Timaru demand. However, there is a degree of natural diversity in when different sites reach their peak, and often this is not coincident with the overall network peak.

[106] Ergo commented that Transpower's prudent demand forecast is often materially higher than recently observed peak demand. Hence many of these GXPs may, be experiencing N-1 security despite zero or negative 'spare N-1 capacity' being shown on Figure 25. The difference between actual peak demand arises due to a combination of the conservative assumptions built in to Transpower's forecast versus real-world experience, which involves varying weather, behaviour and other operational factors.

[107] We note that McCain Foods, while opting for biomass during this RETA project, may investigate future electrification of its process heat.

Using estimated operation profiles of demand from new electric boilers, a more granular view of the timing of peak demand is possible. By overlaying a half-hourly annual profile, for each of the four sites above, on 2022 Timaru demand, we can see the net effect on consumption at the GXP. Below, Figure 34 has Timaru 2022 demand by half hour, while Figure 35 includes the simulated effect of the four additional sites.

Figure 34 - 2022 demand at Timaru GXP, half hourly. Source: Ergo

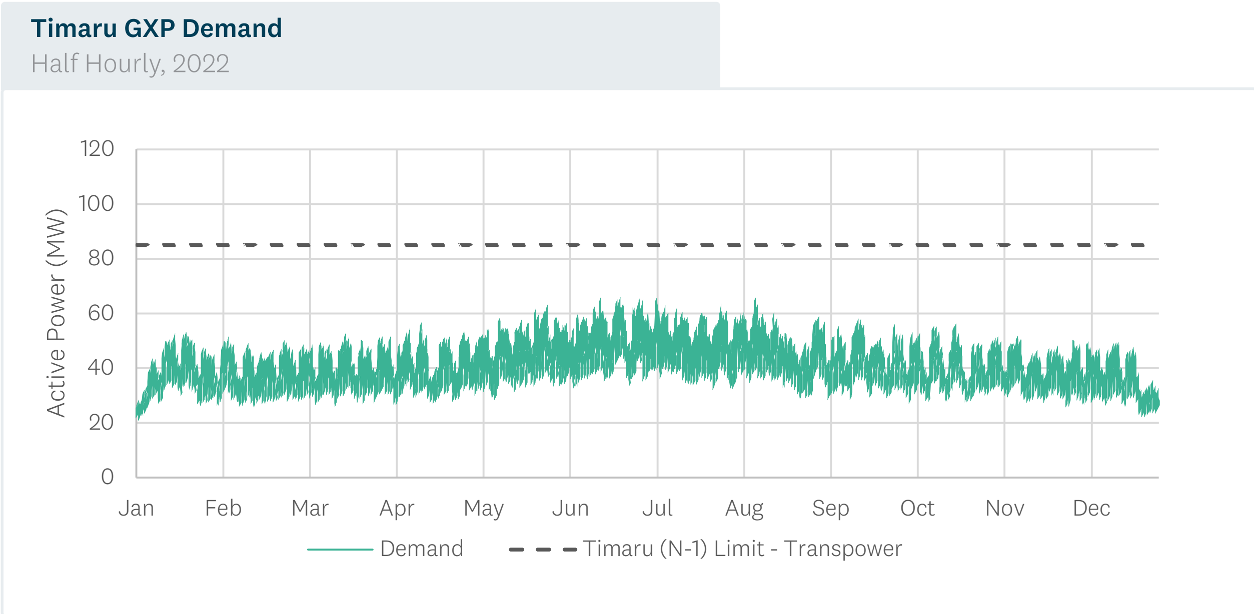
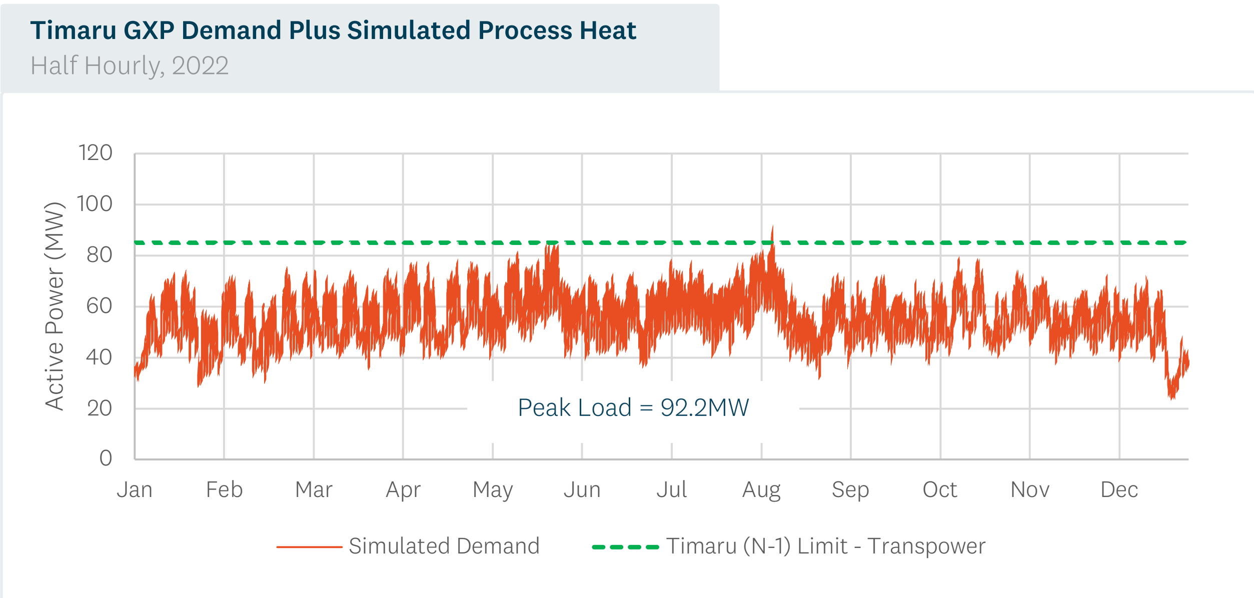


Figure 35 - Simulated Timaru GXP demand after four sites electrify boilers. Source: Ergo



The figures show that, with the addition of the four new sites, Timaru's peak demand increases from its 2022 level of 66MW to a new peak of 92MW – an increase in peak network demand of 26MW. This is 16% less than simply adding the individual peak boiler demands (31MW), demonstrating the benefits of diversity. Moreover, the peak combined demand of 92MW only occurs in one half hour (9 August at 4:30pm) and is the only time the N-1 security constraint is exceeded. This is probably tolerable without triggering the need for expensive investment.

This highlights the importance of EDBs and process heat users sharing a good, common understanding of each sites expected operating profile, at a relatively granular level of detail. This could alter the needs case for expensive upgrades.

8.5 Regional coordination and optimisation

Some of the network upgrades required to enable process heat users' electrification decisions are sufficiently simple to allow the connections to be negotiated between the EDB and the user. However, the interconnected nature of the electricity grid results in situations where the decision of one process heat user impacts the options and decisions that EDBs and Transpower may make, which impact a wider group of consumers. Careful coordination of these decisions increases the chance that benefits to all grid users are maximised.

One such situation exists in Mid-South Canterbury (Figure 35), in respect of:

(a) Fonterra's decision regarding electrification at Clandeboye, which is currently supplied from Temuka.

(b) Alpine's need to upgrade its network capacity to accommodate growth, particularly if multiple process heat users electrify, as outlined in Section 9.4.

Ergo's analysis has shown that if Fonterra electrified a single boiler and a heat pump, this could be enabled through the Temuka GXP with:

- An upgrade to Fonterra's connection assets of around $21M[108].
- An upgrade to the Temuka GXP, and the lines connecting Temuka to the Timaru GXP, costing $28M[109].

Thus, the total cost (to the region) of connecting Fonterra through Temuka is $49M[110].

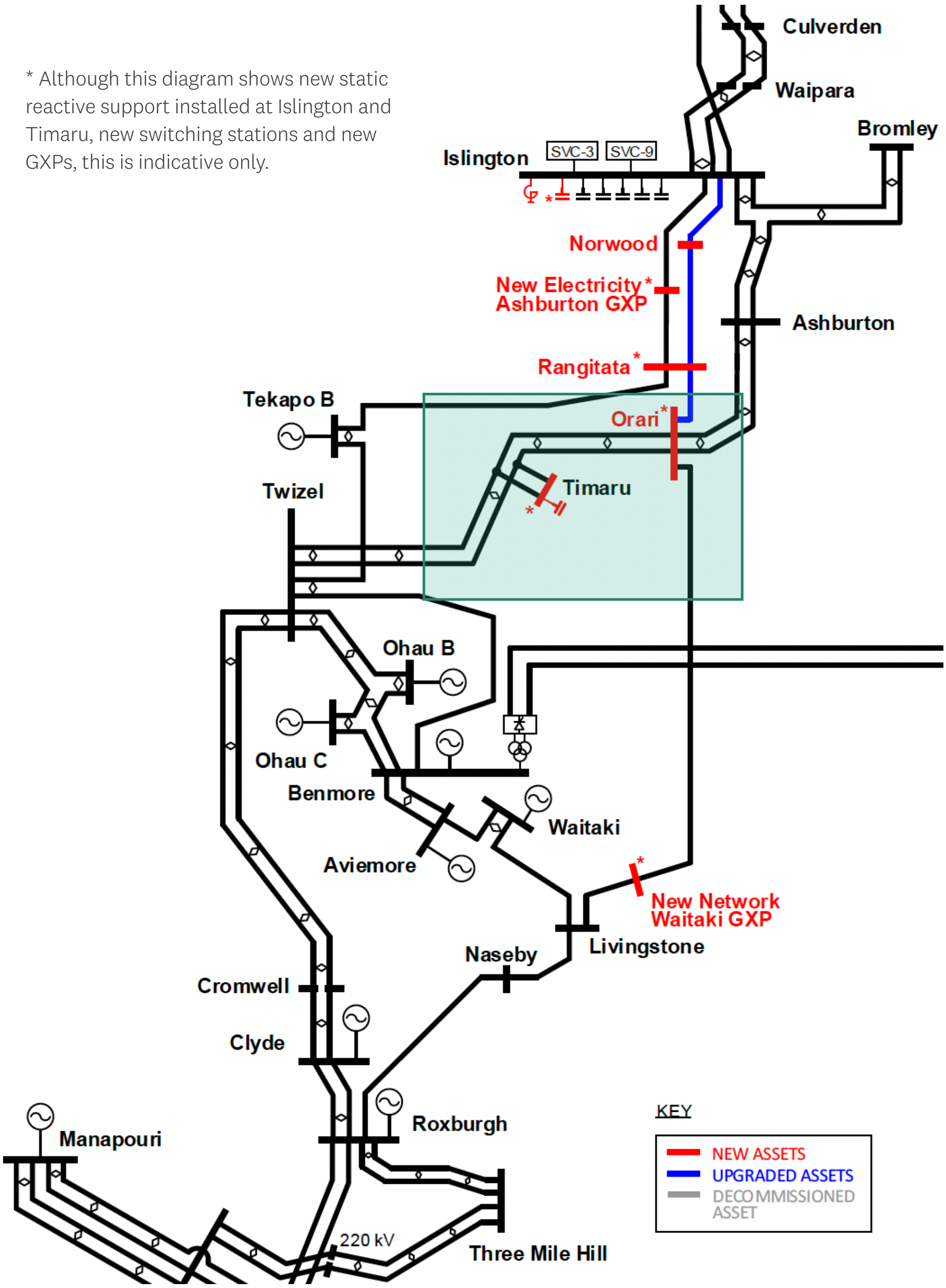
[108] Two new 33kV circuits from Temuka – Clandeboye and a new zone substation.

[109] New (additional) 120MVA 110kV Transformer, 33kV switchboard and 110kV lines upgrade. See Transmission Planning Report (2022), page 330.

[110] Note that this doesn't mean that Fonterra would pay $49M. Fonterra would pay $21M to Alpine Energy as connection costs, whereas we understand the upgrades to Temuka, and the lines connecting it to Timaru, would be allocated to a variety of grid users as a Benefit Based Charge according to the Transmission Pricing Methodology.

Figure 36 - Potential upgraded assets on Transpower's grid near Timaru. Not shown is Temuka connected to Timaru, and Clandeboye connected to Temuka. Source: Transmission Planning Report, 2022[111]

* Although this diagram shows new static reactive support installed at Islington and Timaru, new switching stations and new GXPs, this is indicative only.



[111] Transmission Planning Report (2022), page 75.

Alternatively, Ergo proposed that Fonterra could connect directly to the grid at a new switching station at Orari. This would remove Fonterra's existing and new demand from Temuka reduce demand at Temuka as well as the lines supplying Temuka from Timaru.

Ergo calculated the cost of connecting Clandeboye to Orari at $51M, for a double circuit 110kV connection and new GXP at Clandeboye.

The cost of these two options is very close, and the difference is well within the margin of error expected for this analysis. However, more strategic regional considerations may lead one solution to be preferable over the other, such as the potential for a connection of Fonterra at Orari to open future optionality for Temuka load growth.

In their Transmission Planning Report, Transpower also highlighted a third option relevant to Temuka, which is to connect Temuka to Orari[112]. No costs were provided, but we note it does create many of the benefits of the two options costed above.

We understand the parties involved in these inter-related decisions have been in discussions that move beyond the options costed above to more advanced solutions. This is a positive outcome and highlights the importance of a coordinated and collaborative approach to investment at the regional level.

Aside from a better outcome being agreed, the example highlights some potential barriers to being able to execute an investment which is in the interests of the regional economy. The timing of Fonterra's commitment to electrify any boilers, Transpower's establishment of the Orari switching station (including Commerce Commission approval)[113], and the desire of the Timaru process heat users to electrify would all have to align in a way that satisfied the regulatory requirements of network investment. It may not be possible for network owners to obtain necessary approvals for an investment that maximises a risk-weighted assessment of regional economic benefit, due to the presence of risk or mis-aligned timing.

We recognise that network companies' (Transpower and EDBs) ability to invest is regulated by a very complex piece of legislation (Part 4 of the Commerce Act). Just-in-time infrastructure investments are attractive from the perspective of maximizing certainty of the need, but they may foreclose the ability for parties to develop superior outcomes.

The resulting risk can be a chicken-and-egg situation, where neither the network company nor the process heat user can provide their respective boards with the confidence to invest. We have highlighted one such example in Section 9.5. This may lead to unintended consequences – even if biomass is an alternative option, this will have consequential effects on the local biomass resources and thus cost for all parties moving to biomass.

We understand the network companies are advocating for regulatory change in this respect. Transpower has developed a concept for renewable energy zones where these coordination and regulatory issues could seek more pragmatic solutions. One solution could be an expansion of the renewable energy zone concept beyond the supply-side to include the demand-side, as foreshadowed by Transpower[114].

[112] Page 329 Transmission Planning Report 2022.

[113] Transpower has indicated a need date of 2026.

[114] Renewable Energy Zones National Consultation 2022, Transpower (page 4)

8.6 The role of flexibility in managing costs

8.6.1 Why flexibility?

At its simplest, demand-side flexibility is a consumer's ability to be flexible with when they consume electricity. By modifying usage in response to a range of 'triggers' (changing price, a network constraint or failure) sites can reduce costs and generate revenue. This response can be manual (i.e. determined by the consumer in real time) or automated via technology.

In the context of the electrification of process heat, demand side flexibility can have many benefits as outlined below:

- It can help improve the commercial viability and business case of transition projects by reducing upfront capital costs (e.g. optimise network capacity upgrade requirements).
- It can reduce ongoing electricity procurement costs (e.g. by consuming less at times of high retail rates or network charges, i.e. winter morning and evening peaks).
- It can unlock a new revenue stream to help offset project costs.

8.6.2 How to enable flexibility

The analysis above has assessed the cost implications of the electrification of process heat, assuming that:

- Each site operates in a way that suits its own production schedule.
- Except in the case of the Timaru GXP, and Fonterra, that each site's peak demand from the newly electrified process will occur when the rest of the network peaks[115].
- The investment in the network is required if the connection of the electrified process causes network security to fall below its current level (i.e. from N-1 to N).

However, control of even very complex production processes can be 'smart', in that the process can respond dynamically to signals from the electricity network and market.

In fact, some of this technology has existed for decades – for example, the ripple relays that allow domestic hot water elements to be switched off, or frequency relays that allow large industrial processes to participate in the instantaneous reserve market[116]. More recently, though, the control technology, automation, predictive algorithms, and communications have evolved to make these mechanisms smarter and more precise. In the vernacular of the electricity market, it allows consumers of almost any scale to provide 'flexibility services' to network companies and the electricity market, whereby their consumption of electricity adapts continuously, or in specific situations, to what is happening on the network and market.

[115] This is not true of all sites: in the case of loads connecting to the Timaru GXP Ergo tested an estimated operating profile against existing patterns of demand and determined that full additivity of peak demand did not result: natural load diversity reduced the overall peak.

[116] This is part of New Zealand's wholesale market design, whereby large loads and generation are paid to be on standby in the event that a large system component fails, thus causing frequency to fall.

In the context of the electrification of process heat, this creates a number of opportunities for sites to lower their electricity procurement costs, or – in some scenarios – earn additional revenue from the electricity market. Specific opportunities include:

i. **Wholesale market response:** Section 9.2.1 outlined how the wholesale market is dynamically adjusting to supply and demand conditions in real time, and thus wholesale prices are constantly changing. Sites that choose to be exposed to this wholesale price and that can respond to these prices dynamically will lower their overall procurement cost by consuming less when prices are high, and more when prices are low.

ii. **Minimising retail costs:** Section 9.2.3 outlined how sites that choose to face a more stable retail tariff (rather than direct exposure to wholesale prices) will likely be provided with a set of 'shaped' prices that (at the very least) reflect time of year, weekdays vs other days, and day vs night (see Figure 28). Some pricing arrangements may have more granular prices (e.g. different prices for each 4-hour 'block' of the day). This provides incentives for site operators to schedule production in a more predictable way (compared with a volatile wholesale price), again lowering electricity procurement costs by scheduling production away from high priced periods.

iii. **Dry year response:** It is relatively well known that, due to the dominance of hydro in New Zealand's electricity system, the system occasionally experiences 'dry years' where low inflows persist for weeks and potentially months. This can raise wholesale market prices significantly for a prolonged period, and electricity retailers may be willing to incentivise consumers to reduce demand for this period. This obviously would have significant consequences for manufacturing processes, although sites with dual-fuel capability (e.g. electricity and coal) could switch from electricity to coal during these periods with little impact on their operations.

iv. **Minimising network charges:** As discussed in Section 9.2.4, EDBs may price some component of network charges based on the consumption of the site at peak network demand times (e.g. weekday morning and evening peaks). By reducing demand at these times, network charges may be able to be reduced.

v. **Reducing capital costs of connection:** Similarly, when considering the capital cost associated with accommodating newly electrified processes, Section 9.3 outlined that a key factor is the current spare capacity at peak times in the existing network. Flexibility in electricity consumption can potentially reduce the cost of network upgrades in two different ways:
   - Ensuring demand from the site is reliably[117] lower during the times of peak network demand (when spare capacity is at its lowest), thus reducing the amount of network investment required from the network company.
   - Allowing the site's demand to be reliably interrupted should a part of the network fail (known as a 'Special Protection Scheme'). The network company may, based on a risk assessment, allow network security to drop from N-1 to N-0.5, or N at peak times (see Section 9.3.2), thus requiring a lower level of investment in network upgrades, on the understanding that should a component of the network fail, the site will immediately[118] reduce demand so that the network remains stable.

[117] This would have to be sufficiently reliable to give the network company the confidence to scale back its investment.

[118] Depending on the nature of the security limitation, this may be required to be instantaneous, or may permit up to 15 minutes for the response to occur.

vi. **Other market services:** Finally, there are a number of 'ancillary services' that Transpower, as the electricity 'system operator' must procure which help it manage the whole system's stability and resilience. A reliably responsive demand site may be able to provide services into these markets, and earn revenue from them. Participation can be as little as one to two response events per year that require a load drop of only a number of minutes. We note that the industry is currently discussing how these services may evolve as the amount of intermittent wind and solar increases on the system, including new types of ancillary services that may arise[119].

Of course, altering the production of process heat in order to provide flexibility services (i) – (v) above has consequences (and potentially cost implications) for the site. Lost production during high priced periods, for example, must be recovered at another time – depending on the nature of the process, the flexibility may be limited.

However, there are a number of ways in which thus flexibility can be enabled. if the site can increase its use of thermal storage (e.g. hot water[120]), this can enable flexibility. Alternatively, as mentioned above, a secondary standby fuel could be maintained. Responses could be optimised around production constraints and be automated to reduce labour costs associated with manual decision making.

8.6.3 Potential benefits of flexibility

Enabling flexibility in these ways will increase cost but may be more than offset by the reduction in electricity costs or the capital contribution to network upgrades. The benefits of enabling flexibility – in terms of reduced consumption costs and capital requirements for network upgrades - could be significant. Further, as the electricity system reduces its use of fossil fuels (coal, natural gas, and diesel) in line with emissions prices, and instead builds lower cost wind and solar, the system will require more flexibility from other sources, including consumers. This flexibility could well become a premium product.

There have been a range of analyses of the potential value (to the system) of demand flexibility in the New Zealand system. These range from $150,000 - $300,000[121] pa for every MW of demand that can be reliably moved away from the overall network peak.

[119] See https://www.araake.co.nz/projects/flexforum/. Note that, in some situations, process heat organisations may be able to receive revenue for a number of demand side flexibility services.

[120] Other methods include ice slurry storage, hot oil storage, steam accumulators.

[121] See *Reeve, Stevenson, Comendant (2021), Cost-benefit analysis of distributed energy resources in New Zealand*. Available here: https://www.ea.govt.nz/assets/dms-assets/28/Cost-benefit-analysis-of-distributed-energy-resources-in-New-Zealand-Sapere-Research-Group-final-13September.pdf; Orion (2023), 1 March 2023; Boston Consulting Group (2022), The Future is Electric.

This may not necessarily reflect the reduction in electricity cost that a RETA site may be able to realise. However, the Electricity Authority's independent Market Development Advisory Group (MDAG) estimated the electricity cost reductions that an existing process heat site could realise in a future system with a very high degree of renewables[122]. Notably:

- **It estimated that a process heat site using expanded hot water storage could save between 8% and 18% of its electricity procurement costs if it responded dynamically to wholesale prices (option (i) above).**
- **It also estimated that a process heat site that maintained an additional standby supply of fuel and boiler that could substitute for its electric boiler in a dry year could save around 16% of its electricity procurement costs (if it were exposed to wholesale prices).**

These figures do not include any benefits associated with reduced network charges, or the capital costs of upgrades to the distribution network to facilitate an increase in electricity demand, if this process heat demand had been new (i.e. (iv) and (v) above). These would be in addition to the savings noted above.

We note that, while MDAG's simulations assumed the process heat site was exposed to wholesale prices, this need not be the case for savings to be realised. If the site purchases power through a retailer, then the retailer would save the wholesale costs if the site responded and should share those savings with the site. Of course, this requires an arrangement between the retailer and the site as to when the alternative fuel needed to be switched in, how much notice was given, and what savings would be shared.

8.6.4 Who should process heat users discuss flexibility with?

RETA sites should consider their ability to provide flexibility, and the potential associated costs and implications.

Once process heat users have assessed the degree to which they can be flexible with their electricity consumption, or the security level they require from their connection, they should approach:

- **EDBs** to assess whether the flexibility can reduce the cost of connecting the new electric boiler to the network. EDB's may also be willing to pay for a process heat user's flexibility in order to defer wider network upgrades (sometimes referred to as a 'non-network alternative').
- **Electricity retailers** to determine the extent to which they will incentivise the process heat user to be flexible in their consumption through the electricity tariff the retailer provides through, for example, peak and off-peak pricing.
- **Electricity retailers, flexibility service providers[123] and consultancies** to assess the degree to which the site's response to these signals can be automated.

[122] See https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/consultation/price-discovery-in-a-renewables-based-electricity-system/ , specifically the Demand Side Flexibility case studies available at https://www.ea.govt.nz/documents/1254/DSF-case-studies-FINAL-1.pdf

[123] Examples of flexibility providers include Enel X and Simply Energy

9 Organic waste

The recovery of organic materials presents both an opportunity to eliminate waste and pollution, and to better circulate products and materials. A number of opportunities exist to divert organic waste from landfill, these include:

- Use as stock feed
- Composting
- Food re-distribution
- Energy recovery – for example through combustion or anaerobic digestion

Across the Mid-South Canterbury region, the first three diversion activities are currently undertaken by a number of processors. This section considers the potential for energy recovery as an option for organic waste.

As such, energy production is only one potential use of organic materials generated in the region. A circular economy approach looks to maximise the value of all materials including by-products and waste. This means that rather than seeking the lowest cost approach to managing a specific unwanted material the focus is on maximising the value of that material. In some cases realising that value requires collaboration with others (to achieve scale or make use of specific material properties).

9.1 Sources of Mid-South Canterbury waste information and data

A variety of data has been collated to understand the types of industrial organic waste streams within the region, the current utilisation of these, and provide an assessment of the potential utilisation and scale for process heat production.

A desktop-based assessment was completed building on reports and data provided by Venture Timaru's Sustainable is Attainable programme. The Sustainable is Attainable dataset was compiled in 2021, with additional data collected for this assessment through online meetings, emails and phone conversations. The approach adopted was to check and update existing information as well as collect additional information where available.

In-person site visits were also undertaken with processors of meat, dairy, seafood and other food and beverage across the region. These visits served to substantiate data and provide a basis for assumptions to be made where necessary for similar producers of organic waste. Data sources are noted in Table 16.

Cumulatively, this data serves to build a picture of where the region is now in terms of relevant policy, energy use, organic waste production and material flows.

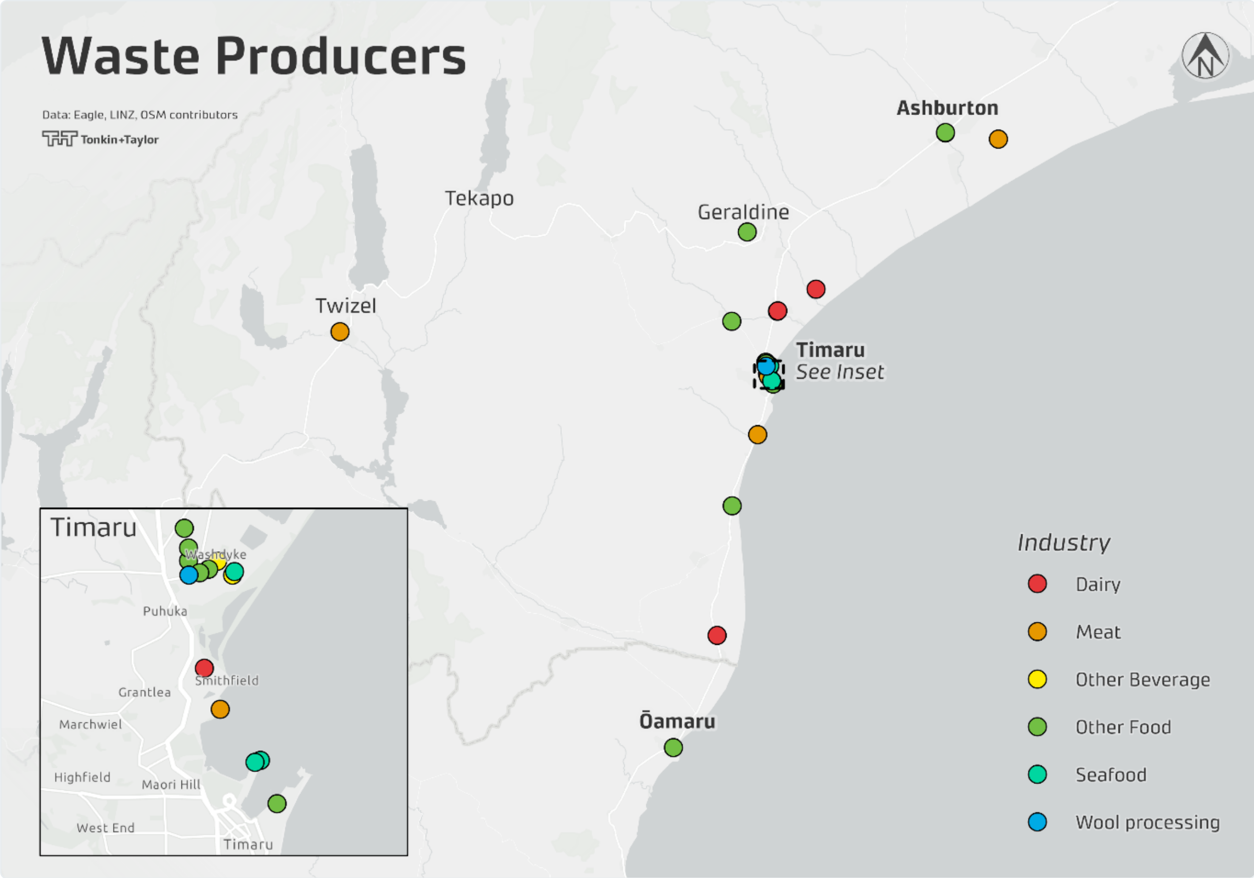
Table 15 - Data Sources for Mid-South Canterbury Waste Study

Data Source	Application
Sustainable is Attainable	Organic waste generation
Stakeholder discussions	Organic waste generation, quantities and end markets
Waste assessments (Timaru, Waitaki, Ashburton, Mackenzie, Waimate Councils)	Organic waste disposal avenues (Landfills)
Trade waste sampling results	Wastewater generation and characteristics (COD, suspended solids where available)
Private waste collection data	Organic waste quantities

Table 16 - Industry sector covered in Mid-South Canterbury waste study

Industry	Number of processors in region	Number of processors where data was received (note in some cases only partial data was provided)
Dairy	4	3
Meat	10	3
Seafood	3	2
Wool	1	1
Beverage	3	2
Food	21	9

Figure 37 - Locations of waste producers participating in RETA Mid-South Canterbury waste study



9.2 Existing end markets for organic waste materials

There is a variety of existing infrastructure suitable for processing organic materials given their location, type, and volume in the region. The processing of industrial organic waste is managed by a combination of private sector organisations, ad-hoc agreements, and business-to-business partnerships. For the most part, these arrangements are determined by a combination of ease to the producer of the organic waste, the cost or revenue, and the ability to obtain and maintain resource consents.

While some processing of organic waste and by-products does occur at processing sites (Silver Fern Farms (Pareora), ANZCO, Sanford Limited), waste management is not seen as a core activity for food/beverage processors. This makes options such as selling for profit or removing from site for no cost attractive for organic waste management. This avoids the need to have specialist technical expertise in-house, for example, rendering, composting, and allows plant managers to focus on core activities.

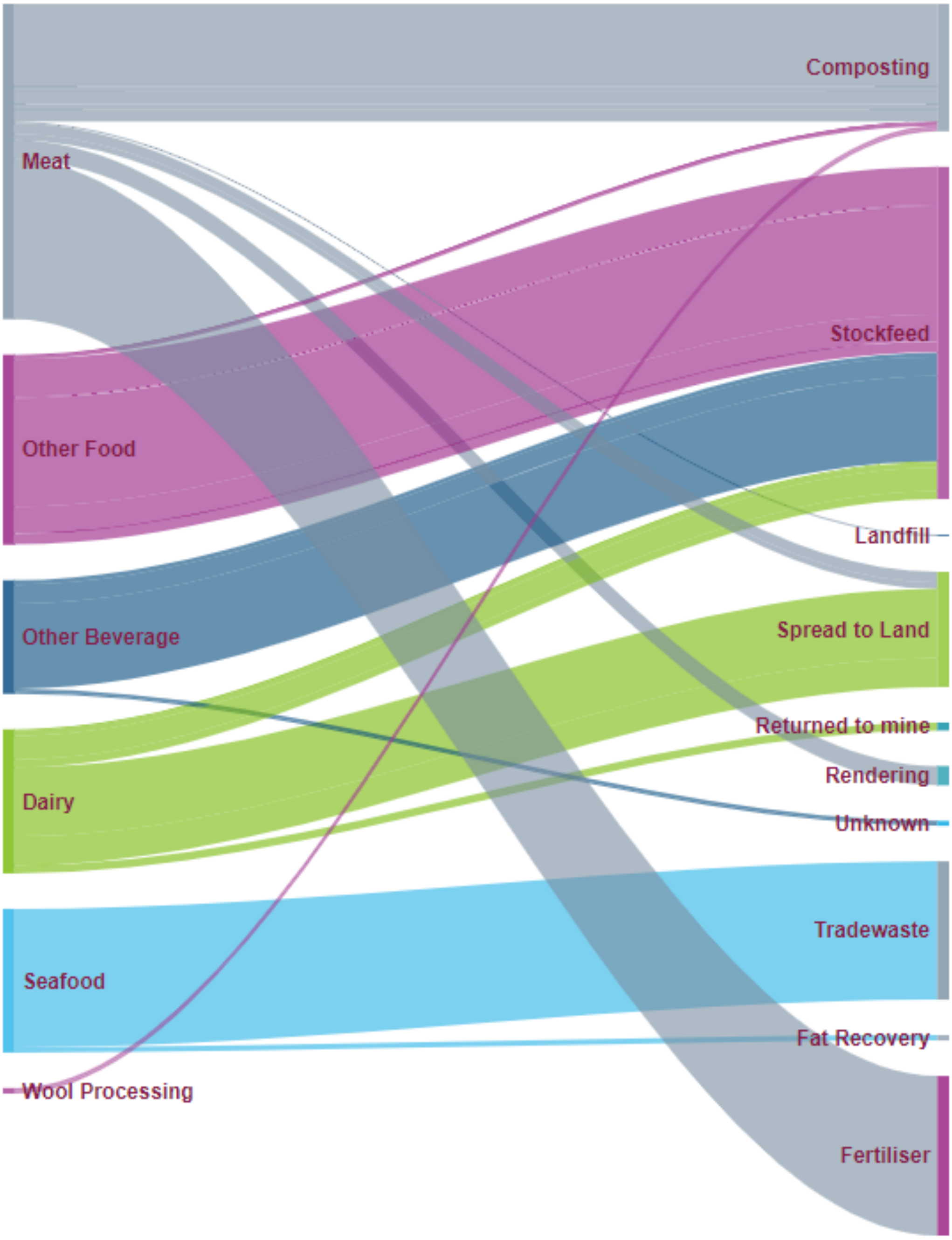
Current destinations for processing and final disposal of organic by-products and organic waste are listed below:

- NZ markets (products to market or ingredients for onward processing into products)
- Export markets (product or for further processing)
- Rendering
- Fat/oil recovery
- Stock feed
- Composting
- Wastewater treatment (both onsite and also council owned wastewater treatment plants)
- Discharge to land
- Discharge to ocean
- Landfill

It is clear reviewing the information on individual material streams across the sectors considered that materials can be utilised or managed in a range of ways. Many materials are suitable for rendering, for use as stock feed without further treatment, or as feedstock for composting. Materials that cannot be sold or provided to other parties to provide nutrient value are managed through land application on processor-owned farms, discharged to trade waste or disposed of to landfill. Again, resource consents are often required for these applications.

An overall summary of material flows reflecting source (sector or location) and current end use is provided in Figure 38. Examining the summary of materials that are available (those that currently cost the producer to manage or where energy recovery may present better value) provides a picture of potential material flows and theoretical energy potential via combustion or anaerobic digestion.

Figure 38 - Flow of materials from sector to end use. Source: Tonkin and Taylor



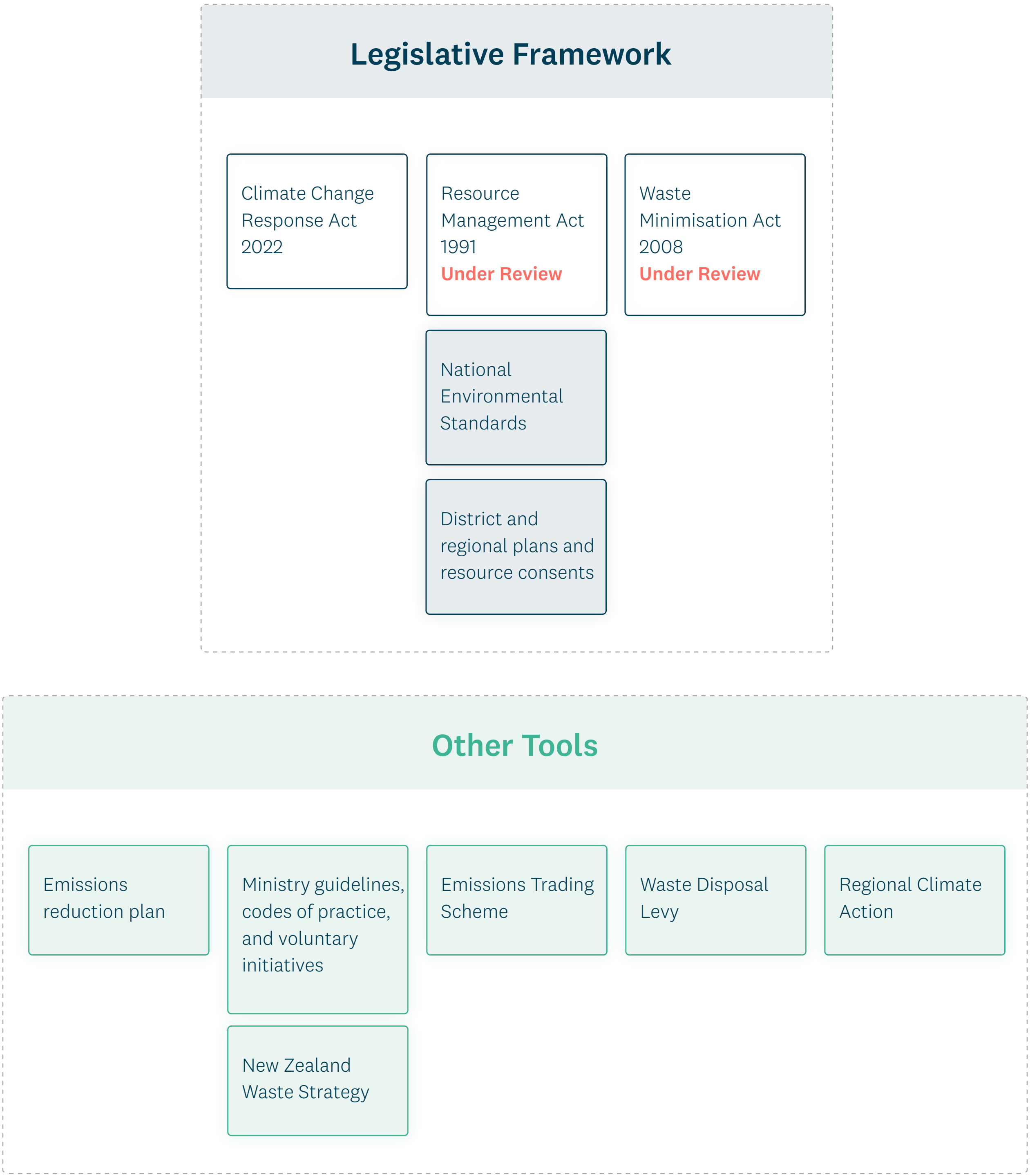
When considering the degree to which processors may change how they currently deal with organic waste (e.g. divert to energy), the drivers behind current destinations chosen by processors needs to be understood. For example:

- Destinations may be chosen which have a better environmental outcome rather than the lowest cost option for that organic material stream.
- Solutions that are more secure may be preferred over those that have some inherent uncertainty.

9.2.1 Changes in the policy context for waste may drive future changes

Changes to waste management and thus flows of waste to end markets in the Mid-South Canterbury region may occur as the national and regional policy context changes. As shown in Figure 39 two key Acts are currently under review, which could change the direction of waste management. Ongoing climate policy implementation will also be significant (e.g. the Emissions Trading Scheme, and the National Implementation Plan including a focus on organic waste recovery).

Figure 39 - Policy context for waste



Key policy reviews and other initiatives currently in train include:

- The national waste policy review, specifically with respect to recycling.
- Progressive increases in the waste disposal levy. This levy is returned to the Ministry for the Environment (MfE) where half of the levy money goes to territorial authorities to spend on promoting or achieving the waste minimisation activities set out in their waste management and minimisation plans. The remaining money is put into the contestable Waste Minimisation Fund administered by MfE. Both sources of funds could bolster investment in organic diversion and better utilisation.
- Impacts on existing resource consents of changes to New Zealand's Resource Management framework, National Environmental Standards and National Policy Statement on Freshwater. Of note to this project is the impact on discharge to land and water consents. Cumulatively, the reform is likely to drive local policy at a regional and district level that:
  - Protects, restores or enhances our air, soil and coastal areas
  - Develops well-functioning, climate-resilient urban areas that improve our quality of life
  - Reduce greenhouse gases

9.2.2 Current/potential waste minimisation efforts

Because many waste materials impose cost on producers, and in some cases represent lost revenue opportunities, there are a range of existing and potential activities to minimise organic waste generated, thus reducing the amount potentially available as energy.

Underutilisation of by-products from primary processing represents a loss of potential revenue and associated disposal costs of by-products. This is increasingly being recognised by the sector, and efforts are in place to minimise the generation of organic waste. These include:

- Investment towards increasing by-product value, improving processing technology, sustainability and science capability.
- Investment at a company level towards added-value products. For example, plasma, collagen, red blood cells, bone powder and cartilage are harvested and sold as healthcare products for human and animal consumption.
- Changes in policy direction including the Fish Quota Management System and the Fisheries Change Programme have provided an incentive to improve commercial fishing practises including trawling. These developments allow for fewer undersize or unintended fish species to be harvested, decreasing total by-catch. With less by-catch, seafood processors typically produce only offal as a by-product for rendering, rather than whole fish. This has decreased total throughput of the rendering facility.
- Rendering throughput is also likely to decrease as investment is made towards added value products from offal (fish and meat) and by-catch. This investment is driven by offshore demand for collagen and nutrient-rich powders and oils derived from ling, oysters, mussels and seaweeds.

9.3 Estimating the energy potential of waste streams in Mid-South Canterbury

9.3.1 Methods of energy production

The two energy-related technologies considered here are combustion and anaerobic digestion (of organic materials generated through food processing activity) to produce heat or fuel for direct use. Ultimately, which approach is adopted for each material will depend on current arrangements, the specific characteristics of the material (calorific value, methane generation potential, water content), location, existing process heat arrangements and options for management of residual materials after energy recovery.

- The combustion of the materials identified in this report will require an approach that can accommodate relatively high-water content and low energy density (compared to conventional biomass). This implies the use of fluidised bed boilers (better at handling ‘wet’ fuel), co-firing with biomass or other higher calorific value fuel and/or pre-drying materials to improve handling and calorific value.
- Conventional anaerobic digestion is suited to low solids content streams with high volatile solids content that is amenable to degradation. Digestion produces biogas (the focus of this report) with digestate remaining that can be further processed into a dewatered product and high strength liquid stream if desired. The liquid removed through dewatering process is often recycled through onsite wastewater treatment processes. The solid product (often 15-20% solids) can be land applied or further processed (thermally dried, vermicomposted or composted). If anaerobic digestion is considered further, research (including bench and pilot scale testing) into the co-digestion of the various material streams will be required to maximise methane yield and optimise digestor design. A key consideration for anaerobic digestion of food processing residues will be securing an outlet for digestate. This could take the form of either 2-5% solids, liquid product, or a 15-20% dewatered product. Without further processing this product could be land applied subject to suitable consents. Further processing could generate a saleable soil amendment product – vermicompost, compost or dried granule.

9.3.2 Calculating energy potential

The energy potential for the material streams identified have been estimated using publicly available information and/or data provided by the waste generators where they have completed their own assessments.

Key parameters considered include:

- The total quantity of material in tonnes and/or m3.
- Solids content (%).
- Calculated solids quantity.
- Chemical Oxygen Demand (COD), Biological Oxygen Demand (BOD) and/or Volatile Suspended Solids (VSS) – variously used to estimate methane generation potential.
- Biogenic Methane Potential – m^3 of methane generated per T of BOC, COD or VSS.
- Calorific value of methane (GJ per m^3 of methane).
- Calorific value of 'wet' or 'dry' material (normally GJ/tonne) through combustion. Where necessary adjusted to reflect solids content, providing a net calorific value.

In some cases net calorific values have been provided by processors in Mid-South Canterbury. In most cases values for methane potential and net calorific value from the literature have been used to provide an indicator of energy potential. Testing of actual waste streams in the Mid-South Canterbury region, to derive actual calorific value and or methane generation potential will be required prior to more detailed consideration of decarbonisation opportunities.

Using the parameters above the theoretical energy potential of various material streams has been calculated.

The calculated net energy potentials do not account for:

- Boiler efficiency.
- The availability of suitable infrastructure, for example:
  - Fluidised bed boilers to handle sludge (spadable) materials.
  - Gas boilers (for methane/biogas).
- The availability of fuels suitable for co-combustion with sludge, e.g. wood chip or sawdust.
- The interaction of materials in digestion, i.e. enhancing or inhibiting digestion performance.

Table 17 presents a summary of the high-level estimates of energy potential via combustion or anaerobic digestion, and where available indicative costs. Noting that the potential energy generation is either/or and a combined potential and would make up around 3% of the total current process heat requirements of the Mid-South Canterbury region.

Table 17 - Summary table of estimated energy potentials from organic waste streams

Sector	Estimated quantity (wet tonnes/year)	Energy potential via combustion (GJ/year)	Energy potential via anaerobic digestion (GJ/year)	Existing Indicative costs ($ per year)	Current use
Dairy	19,150	>100,000 GJ	35,300 GJ	$200,000-$400,000	Stock feed
Meat processing	4,300	45,500 GJ	17,400 GJ	Nominal	Composting
Seafood processing	26,000	Not applicable	9,900 GJ	$18,000	Trade waste
Other food & beverage processing	55,600	32,000 GJ	120,000 GJ	Nominal	Stock feed
Wool processing	1,000	6,500 GJ	4,500 GJ	Nominal	Fertiliser
Estimated total	**80,050**	**>184,000GJ**	**187,100GJ**	**Approx. $400,000**	**-**

As noted above, further work is required to understand net energy potential and possible energy plant configuration and performance prior to determining whether to progress with the opportunities suggested by the preliminary energy potential figures presented in this report.

Where data was not received from processors, assumptions have been made on the likely quantities of organic waste ‘available’ produced by large scale processors. These are shown in Table 18.

Table 18 - Additional summary information where estimates (rather than data) had to be used

Sector	Estimated quantity (wet tonnes/year)	Energy potential via combustion (GJ/year)	Energy potential via anaerobic digestion (GJ/year)	Comment
Dairy (DAF sludge)	5,400	>30,000 GJ	9,400 GJ	Spread to land
Meat processing (paunch grass)	550		1,900 GJ	Composting
Estimated total	**5,950**		**11,300 GJ**	**-**

9.4 Conclusion

The theoretical energy potential for available organic waste within the Mid-South Canterbury region from anaerobic digestion is around 187,100 GJ. Alternatively, combustion could generate around >184,000 GJ of potential energy. This is approximately 3% of the total process heat required in Mid-South Canterbury today.

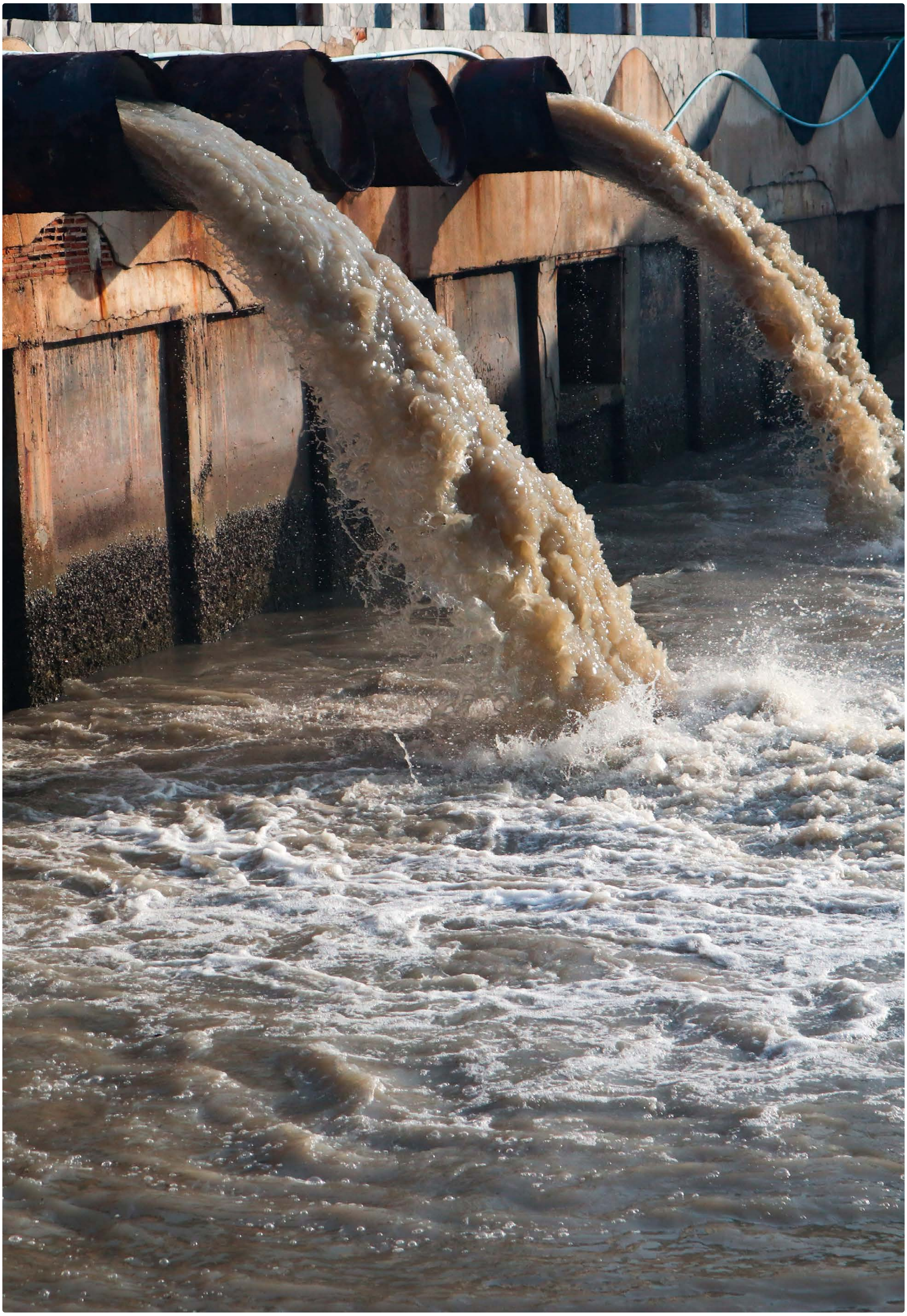
While the energy potential is relatively small, as discussed above there are a range of co-benefits alongside energy production and emissions reduction, such as improved environmental performance.

To activate the potential most efficiently, location and scale are important.

- Location is important, as the types of materials within the available organic streams identified generally have low energy density. Local use may be a better overall emissions outcome to minimise the use of transport. That said, due to the locations of the available organic streams, transporting to a central location may be warranted where economies of scale enable more beneficial approaches. Given the high moisture content of organic waste, transport costs (related to material weight and volume) will require further investigation including consideration of (enhanced) onsite dewatering or drying.

- **The potential for a third party to aggregate organic materials (to achieve scale) and supply heat may be an option for processors, allowing the focus to remain on their core business. For example, during on-the-ground discussions where composting is being undertaken onsite, there is preference to move this activity to an offsite location. Many processors use contractors to collect and remove organic waste and by-products offsite already.**

The analysis for Mid-South Canterbury suggests there is potential to bring materials together for energy recovery. This would provide a reasonable contribution to heat demand at a specific site and provide some economies of scale. This is most likely to be viable in specific areas, for example considering a site in or close to Timaru with a single energy recovery operation providing heat to one or more processing sites. Any benefits from aggregation of materials will need to offset the benefits associated with managing materials onsite including avoided transport offsite (with associated costs and emissions).



10 Decarbonisation pathways

As outlined above, a primary driver for the RETA approach is to identify where the collective decisions of process heat users, and potential providers of low-emissions process heat fuel (biomass or electricity), give rise to 'system' challenges and opportunities. These challenges and opportunities may not be apparent to individual RETA projects, as they only become apparent when the collective impacts of many RETA project decisions are considered. If these challenges and opportunities can be anticipated, and the types of conditions under which they might occur, they can be addressed in advance, improving process heat users' ability to make informed decarbonisation decisions.

This section also uses the information from the previous sections to consider different scenarios of the pace and magnitude of electricity and biomass uptake across the whole Mid-South Canterbury region. We refer to each of these scenarios as 'decarbonisation pathways'.

10.1 Sources and assumptions

The modelling that sits behind the simulated pathways relies on an array of assumptions about the decisions individual organisations will make. Some of these relate to the individual characteristics of each process heat organisation in the Mid-South Canterbury RETA, other estimates use the information outlined in Sections 8 and 9 above.

Where possible we have used actual data for this analysis and the main sources of data include:

- Energy Transition Accelerators (ETAs)
- Energy audits
- Feasibility studies
- Discussions with specific sites
- Published funding applications (GIDI and State Sector Decarbonisation Fund)
- Regional Heat Demand Database
- School coal boiler replacement assessments
- Online articles

The emissions profiles and reduction opportunities of all the major sites have been covered off using these sources, covering the majority of emissions from Mid-South Canterbury RETA sites. However, for sites where individual ETA data was not available, estimates based on other data available to EECA were made, including:

- Demand reduction opportunities have been estimated to be 10%.
- Heat pumps have been estimated to reduce demand by 15% where the split between hot water and steam is not available.

In order to determine likely fuel switching decisions across a range of industries and boiler sizes, the fuel option (biomass or electricity) which has the lowest marginal abatement cost (see below) is chosen. The assumptions about the key parameters associated with these decisions include:

- Existing fossil fuel boilers are estimated to be 78% efficient.
- Biomass boilers are estimated to be 80% efficient.
- Electric Boilers are estimated to be 99% efficient.
- Capital costs for new boilers were derived from specific individual ETAs where available, or derived from wider ETA data where unavailable.
- Biomass cost estimates have followed a cost path of $21/GJ ($264/t) delivered to the user's site. However, if a significant increase in demand is triggered, the cost is increased to $29/GJ ($365/t) for that additional volume[124]. This is effectively an average cost of the resources identified in Section 8.7, but incorporates the cost of higher-priced wood pellets where boiler conversions are contemplated. To these cost figures an indicative $3/GJ 'margin' is added for organisations who facilitate the biomass chipping, storage and transport, and the potential processing associated with (for example) pellet manufacture.
- A conservative view of electricity upgrade costs required for each site has been incorporated as per Section 9.
- Variable electricity costs have used the central pathway from Section 9.2, along with estimates for distribution and transmission network prices discussed in that section. In some cases we have substituted currently available retail market pricing[125] – targeted at process heat users in the South Island – for the near-term prices from Section 9.2.

[124] These numbers do not match any individual resource illustrated in Section 7.6, as the approach adopted to create the pathways assumed an average cost of the different types of resources available through time, also allowing for the higher cost of wood pellets (not considered in that section) where conversions of existing boilers are being evaluated. It is a somewhat more complex optimisation to integrate the 'stepped' nature of supply illustrated in Section 7.7 with the calculation of MAC values.

[125] For example, Meridian's process heat electrification programme pricing.

However, the following general rules have also been applied to each site, which reflect the decarbonisation decision making process outlined in Section 7.3:

- Demand reduction or efficiency projects are assumed to proceed, and will proceed first, so that boiler sizing decisions are based off the post-efficiency/demand reduction requirements[126].
- If a site only demands hot water at <100°C, there is the potential to replace the entire boiler load with heat pumps (depending on opportunities for heat recovery on site). If a site contains both <100°C water and >100°C heat requirements, a mixed approach may be adopted, using heat pumps for the hot water demands and a boiler conversion or replacement for higher temperature needs.

10.1.1 Calculating marginal abatement costs

For the pathways that involved an optimisation of fuel switching decisions, we need a simple way to determine which fuel they would choose (and when).

In reality, there are a range of other factors organisations face when deciding when to make a decarbonisation decision, and which fuel to choose. These factors will invariably include the cost of the decision, but also may include confidence in future fuel supply, competitor behaviour, funding and financing or consumer expectations. However, these softer factors are harder to model quantitatively.

Our simulated 'optimal' decision making framework presumes that the decision regarding which fuel to switch to, and when, is purely about the change in cash flows (capital and operating) arising from the project. Using discounted cash flow analysis, at an appropriate discount rate, we can calculate a 'levelised cost of emissions reduction' for each project and fuel type (biomass or electricity), also known as a 'marginal abatement cost' (MAC).

MACs are calculated as:

$$MAC\left(\$/_{CO_2e}\right) = \frac{NPV(Project\ Costs\ (\$))}{NPV(emissions\ reduced\ (tCO_2e))}$$

The project costs included in the calculation include all capital, operating and fuel costs, but must not include the future estimated (Scope 1) costs of surrendering NZUs to New Zealand's Emissions Trading Scheme, as this is implied by the MAC[127].

[126] As a result, the total boiler demand from sites post-fuel switching decisions is lower than the demand implied from the process heat regional demand database.

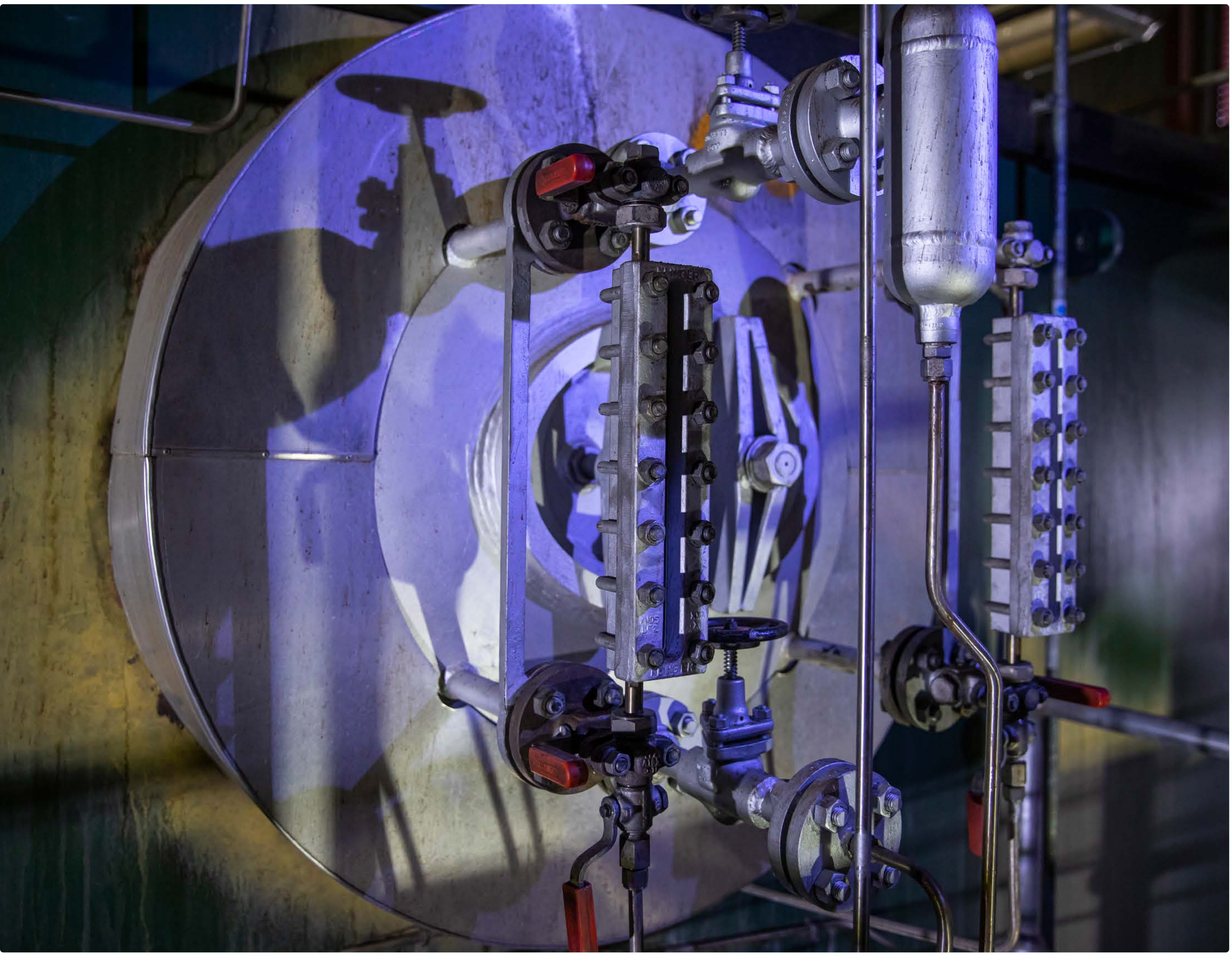
[127] In the same way that calculating the levelized cost of energy must not include any revenue from selling the energy, as the LCOE gives the price at which the decision maker would be indifferent.

10.1.2 Using MAC values to support investment decision making

There are two ways MAC values can support a process heat user's investment decision:

- **Fuel choice:** If there is more than one option available (i.e. biomass or electricity), the MAC also gives a relative ranking of the options expressed in terms of their marginal abatement cost. As stated above, the MAC value effectively provides a 'cost of carbon reduction' expressed in $/tCO2-e. A high MAC value suggests that project's cost of reducing a tonne of carbon dioxide is higher than a project with a low MAC value.

- **Investment timing:** Having determined the option with the lowest MAC, it then can be used as an indication of the best time to invest in decarbonisation by comparing it with likely carbon prices. Ultimately, carbon prices flow through to the fossil fuels used by the RETA organisations via the price of the fuels they use. If the national carbon price is expected to be higher than the MAC value (the 'cost of carbon reduction'), then the organisation will have lower costs in the future by investing in decarbonisation and reducing its exposure to future carbon prices.



New Zealand's cost of carbon is set primarily through the Emissions Trading Scheme (NZ ETS); however the quarterly carbon auctions which determine this price only reflect the current supply of, and demand for, carbon reduction 'units' (New Zealand Units, or NZUs). Many RETA businesses will be aware of the impact of the current carbon price on the price of coal –today.

Comparing the optimal fuel's MAC value against today's carbon price doesn't fully capture what the business will be paying for coal in the future. This is especially important when considering investments in boilers – that will avoid the cost of carbon – that have a life of 20 years (or more). Put another way, decarbonising process heat doesn't just avoid today's cost of carbon, it avoids it over the life of the investment.

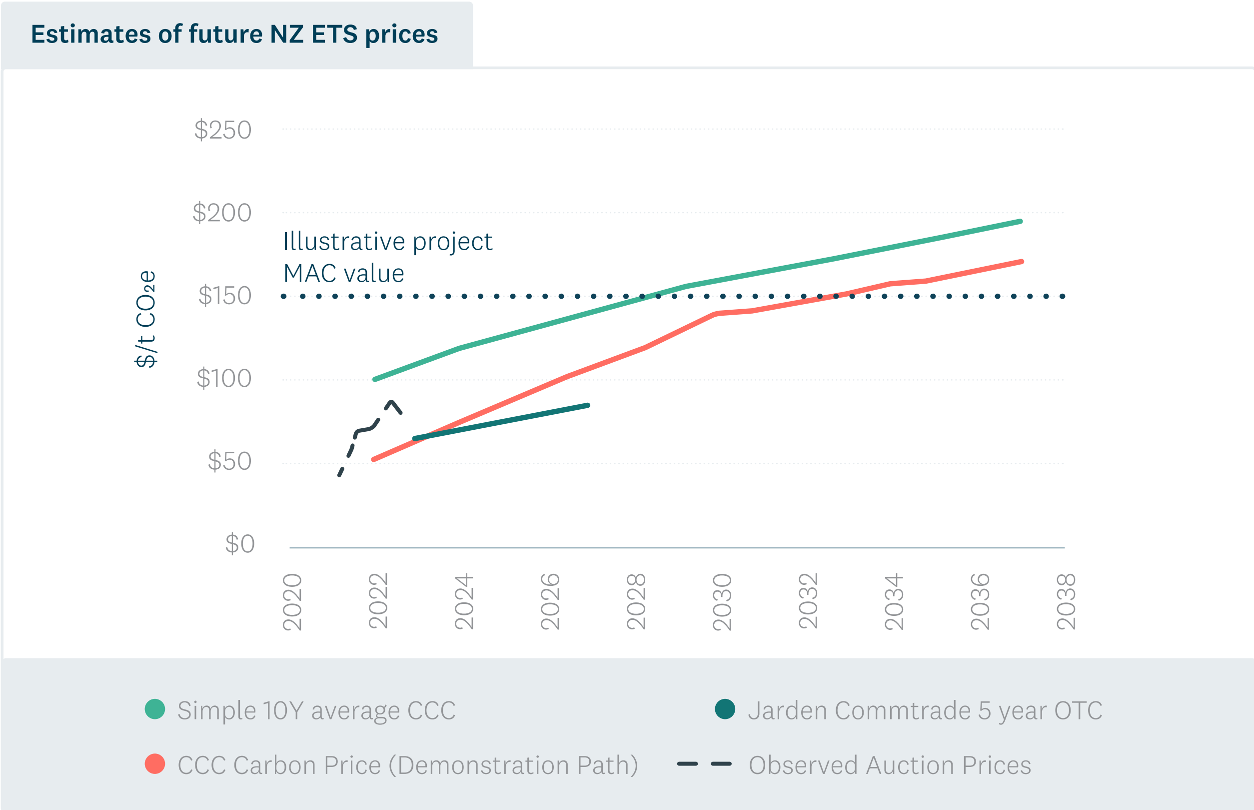
If the carbon price was expected to rise, then the investment would be more attractive than if only today's price of carbon was used. The challenge for many organisations is how to form a view on the carbon price (and thus its impact on the business) in the future[128], should it continue to consume coal, diesel or LPG. There are few publicly available forecasts of carbon prices through which a process heat user can get confidence that carbon prices will reach a level which makes the investment economic. Even then, it is entirely understandable that an investor might 'wait and see' if the increases materialise, before committing investment.

One view on future carbon prices is the Climate Change Commission's (CCC) carbon price pathway from its 'Demonstration Path'[129] (represented as the red solid line in Figure 41). Technically, this is not a 'forecast'; rather, it is the series of modelled carbon prices (to 2050) which are consistent with New Zealand meeting its aspirations around carbon reduction. Whether or not carbon prices actually follow that pathway depends largely on whether government policies and resulting decisions by consumers and businesses meet the 'emissions budgets' recommended by the CCC.

[128] To some extent, this is no different to an organisation considering the future prices of any of their major input costs, except that the carbon price is often already packaged into the cost of the fossil fuel they consume (coal, gas or diesel) and may not be itemised separately by the fuel supplier.

[129] See https://www.climatecommission.govt.nz/news/dive-into-the-data-for-our-proposed-path-to-2035/

Figure 41 - Future views of carbon prices



Recognising that it is the carbon prices over the lifetime of the investment that represent the carbon costs that the organisation will face, we have used the 10-year future average of the CCC's demonstration pathway. This is the green solid line in Figure 41.

The black dashed line shows the outcomes of actual NZ ETS auctions (held each quarter). These are the result of the bids by organisations that need to purchase NZUs, cleared against the volumes made available by the government (at reserve prices).

We have also included one broker's clearing prices of NZU contracts being traded up to 5 years in the future – this offers another view of the market's expectation of carbon prices, as at March 2023[130]. It will likely include the effect of the failed NZ ETS auction that took place in March.

Different future views on carbon prices, and different ways of using those views, could have quite different impacts on the timing of decarbonisation projects proceeding. Assuming that the CCC Demonstration Pathway is a good forecast of carbon prices, Figure 41 shows that a project with a $150/t MAC value would not be committed until 2033 if the decision maker used the current carbon price to trigger the decision, but would proceed earlier –in 2028 –if they used the simple average of the next 10 years of carbon prices implied by the CCC Demonstration Path.

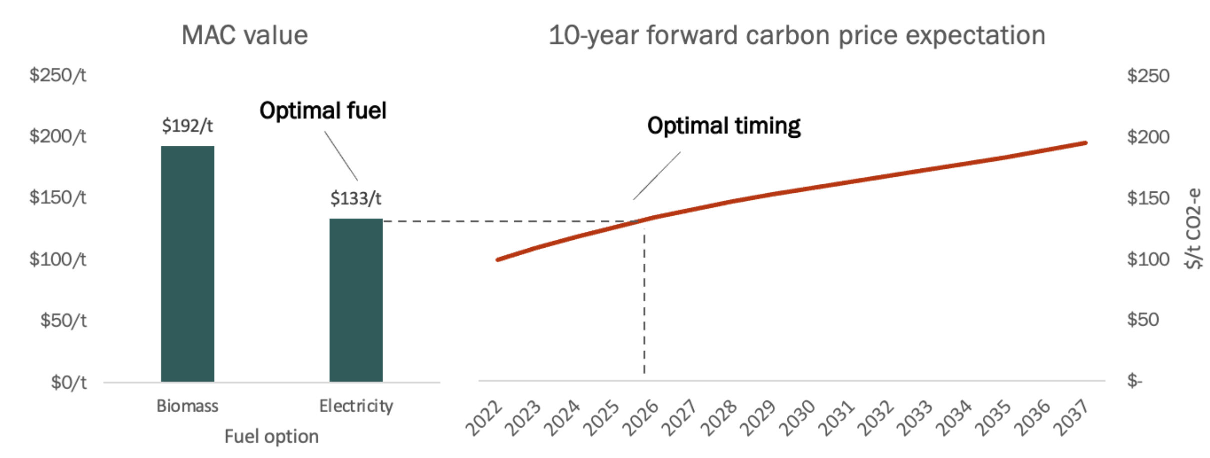
[130] Because NZUs can be purchased today and stockpiled/held for the future, these forward prices contain very limited information about future carbon prices other than the cost of carry (i.e. working capital/interest rates. If, however, the only way to meet NZU obligations in – say – 2026 was to purchase 2026 vintage NZUs, then forward contracts would have significant signalling value.

For this report, we have chosen to use the 10-year forward average of the Climate Change Commission's (CCC) Demonstration Path to determine the investment timing, as we believe this is a better reflection of the actual financial impact of future carbon prices on a long-term investment than just using the solid red line in Figure 41[131].

The overall framework for how we use MAC values to create the 'MAC Optimal' pathway below is shown in Figure 42.

Figure 42 - Illustration of how MAC's are used to determine optimal decision making

Illustration of how MAC's are used to determine optimal decision making



[131] This is not the only correct way to determine investment timing. There are a range of other frameworks for decision making, which could result in earlier or later investment timing.

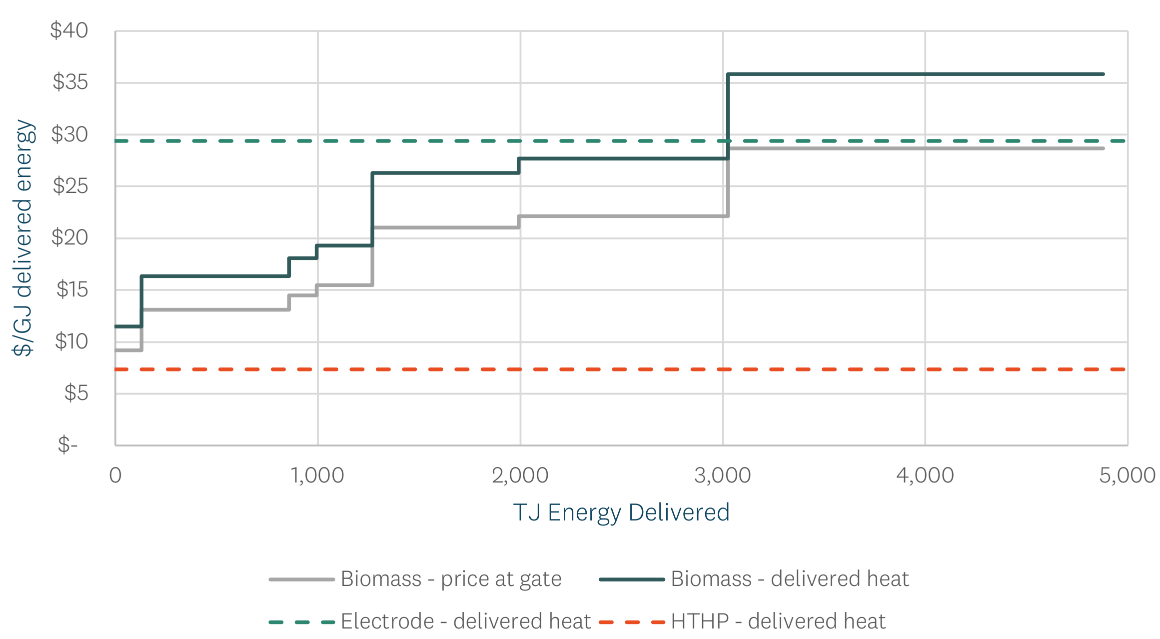
10.1.3 The impact of boiler efficiency on the 'price of heat'

The MAC analysis implicitly trades off all the costs – capital, operating and fuel – to provide a single analysis of the lowest-cost fuel (from an emissions reduction perspective). This (necessarily) incorporates the different efficiencies of the boiler technologies chosen. The delivered cost of biomass (to the 'gate' of the site) cannot be directly compared with the delivered cost of electricity (or any other fuel) without accounting for the fact that biomass boilers have approximately 80% efficiency, whereas electrode boilers have close to 99% efficiency. On the same basis, heat pumps have coefficients of performance that are four or higher. The cost per unit of heat received by the process is therefore different from the cost per unit of the energy delivered to site.

In Figure 43, we illustrate the difference between these cost concepts using the bioenergy supply curve from Section 8.7 (for a biomass decision) and the electricity price path from Section 9.2 (for an electrode boiler, and heat pump decision). Note that these are only the variable costs of the fuel, and do not incorporate the fixed costs associated with different investment decisions (which are taken into account with the MAC calculation). The biomass price does not account for any margin that suppliers may seek on the various bioenergy resources.

Figure 43 - Comparison of the variable costs of biomass and electricity from a delivered heat perspective. Sources: PF Olsen, Ahikā/MG, EnergyLink, EECA.

Comparison of fuel prices
2028-2032



10.1.4 Resulting MAC values for RETA projects

The range of marginal abatement costs for projects are illustrated in Figure 44 below. Individual MACs have been calculated for each site's demand reduction and heat pump projects, as well as the optimal choice of fuel for boilers. These charts include 11 projects that have already been confirmed.

Figure 44 - Number of projects by range of MAC value. Source: EECA

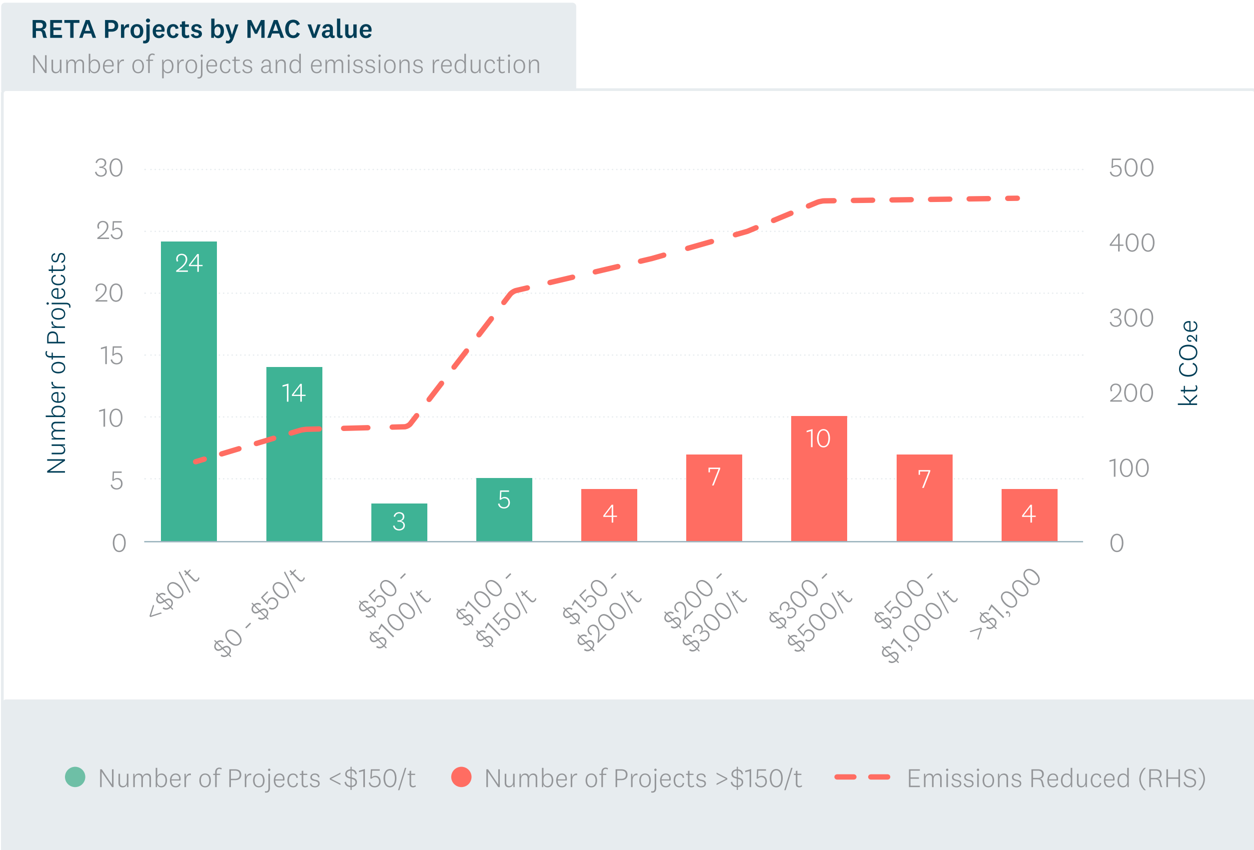
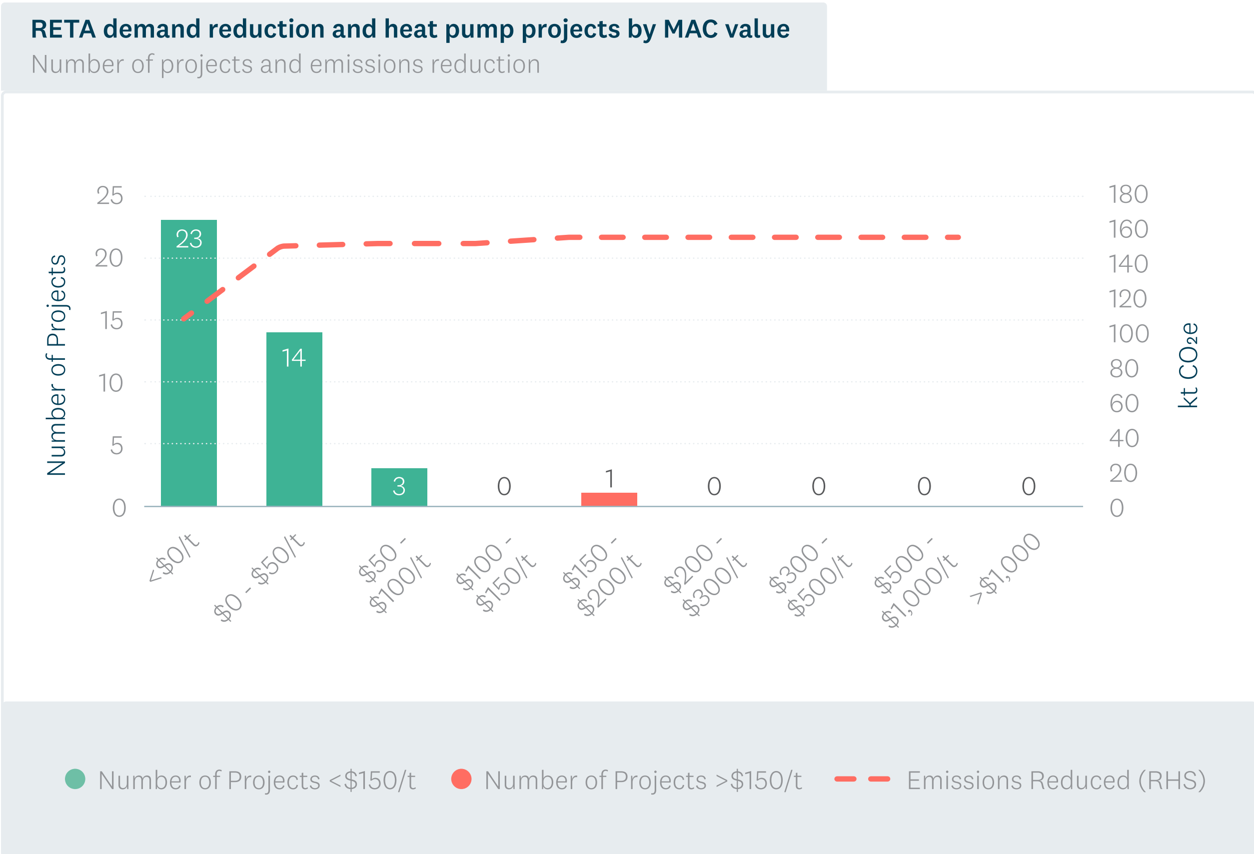


Figure 44 shows – highlighted in red – that 46 projects would have a positive net present value (NPV) at some point in the period to 2037), if NZ ETS prices rose in line with the Climate Change Commission's carbon price projections[132]. The figure also displays the cumulative emissions reduced as the MAC value increases, showing that 73% of the total emissions reduced through these projects can be achieved at carbon prices less than $150/t (which is the Climate Change Commission's estimated carbon price for 2033). In fact, 33% of emissions reductions are economic today, evaluated against a 10-year forward expectation of carbon prices ($110/t, again using the CCC's path).

Figure 45 shows that the majority of these economic projects are demand reduction and heat pump projects, delivering 159kt of emissions reductions. All but one of these projects are economic within the 15 year term of the RETA project.

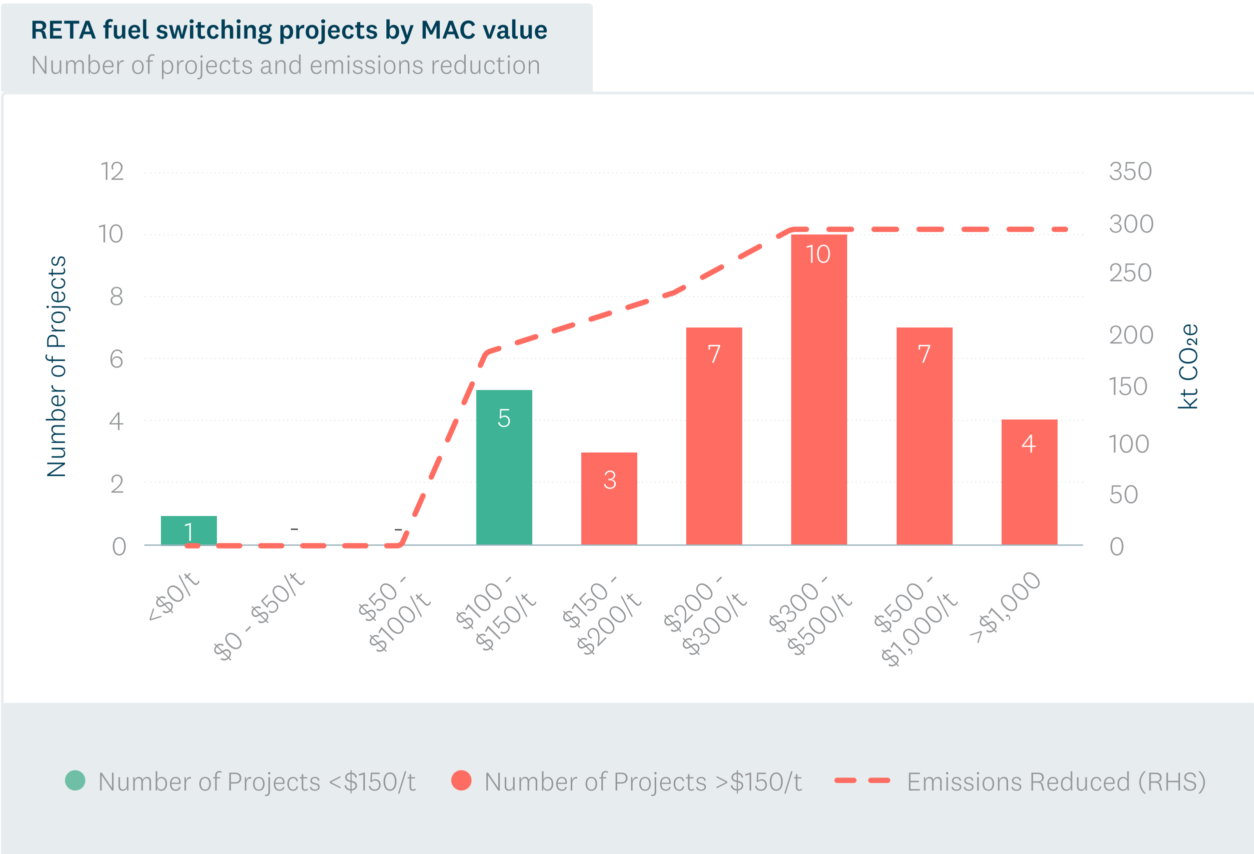
[132] The demonstration path from the CCC's final advice.

Figure 45 - RETA demand reduction and heat pump projects by MAC value. Source: EECA



Fuel switching projects are higher cost (Figure 46), on a MAC basis, reflecting the various combination of site-specific factors, such as the lumpy nature of potential electricity upgrade costs as calculated in Section 9 (where relevant), the operating profile over the year, and the overall utilisation of the boiler capacity.

Figure 46 - RETA fuel switching projects by MAC value. Source: EECA



Notwithstanding the higher cost of fuel switching, 60% of emissions reductions from fuel switching are achievable at MAC values <$150/t. There could be a range of ways cost reductions could be achieved to make the remaining projects more viable over the term of the RETA, for example, securing access to lower cost biomass resources, enabling plant flexibility to reduce the cost of electricity connections and/or electricity consumption, or access to targeted co-funding. We consider the impact of co-funding, amongst other scenarios and sensitivities, below.

10.2 Indicative pathways

Indicative pathways for decarbonisation have been prepared on the following basis. For all pathways, the following constraints were applied to the methodology:

a) Boiler conversions involving facilities owned by the Ministry of Education, Ministry of Health or the Department of Corrections are all assumed to occur by the end of 2025, consistent with the Carbon Neutral Government Programme[133].

b) All RETA decarbonisation projects are executed by 2037 in line with the Government's aspiration to phase out coal boilers by 2037[134]. This means that any projects that are still not 'economic' using our MAC criteria (illustrated in Figure 42) by 2036, are assumed to be executed in 2036.

The pathways were then developed as follows:

Pathway name	Description
BAU – Biomass Centric	All unconfirmed site fuel switching decisions proceed with biomass at the timing indicated in the organisation's ETA pathway. If not indicated, timing was set at 2036.
BAU – Electricity Centric	All unconfirmed sites proceed with electricity as the sole fuel at the timing indicated in the organisation's ETA pathway. If not indicated, timing was set at 2036.
BAU – Combined	All unconfirmed fuel switching decisions (i.e. biomass or electricity) are determined by the lowest MAC value for each project; timing of commissioning as indicated in the organisation's ETA pathway. If not indicated, timing was set at 2036.
Linear	Each site switches to the fuel with the lowest MAC value for that site; projects ordered and timed to achieve a relatively constant annual level of emissions reduction (within reason)[135].
MAC Optimal	Each site switches its boiler to the fuel with the lowest MAC value for that site. Each project is timed to be commissioned in the first year when its optimal MAC value first drops below a ten-year rolling average of future carbon prices[136].

[133] This programme prioritises the phaseout of coal-fired boilers from the public sector, with the focus on largest and most active by the end of 2025. See https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/carbon-neutral-government-programme/about-carbon-neutral-government-programme/

[134] All RETA decarbonisation projects are executed by 2037 in line with the Government's aspiration to phase out coal boilers by 2037See https://www.beehive.govt.nz/release/government-delivers-next-phase-climate-action

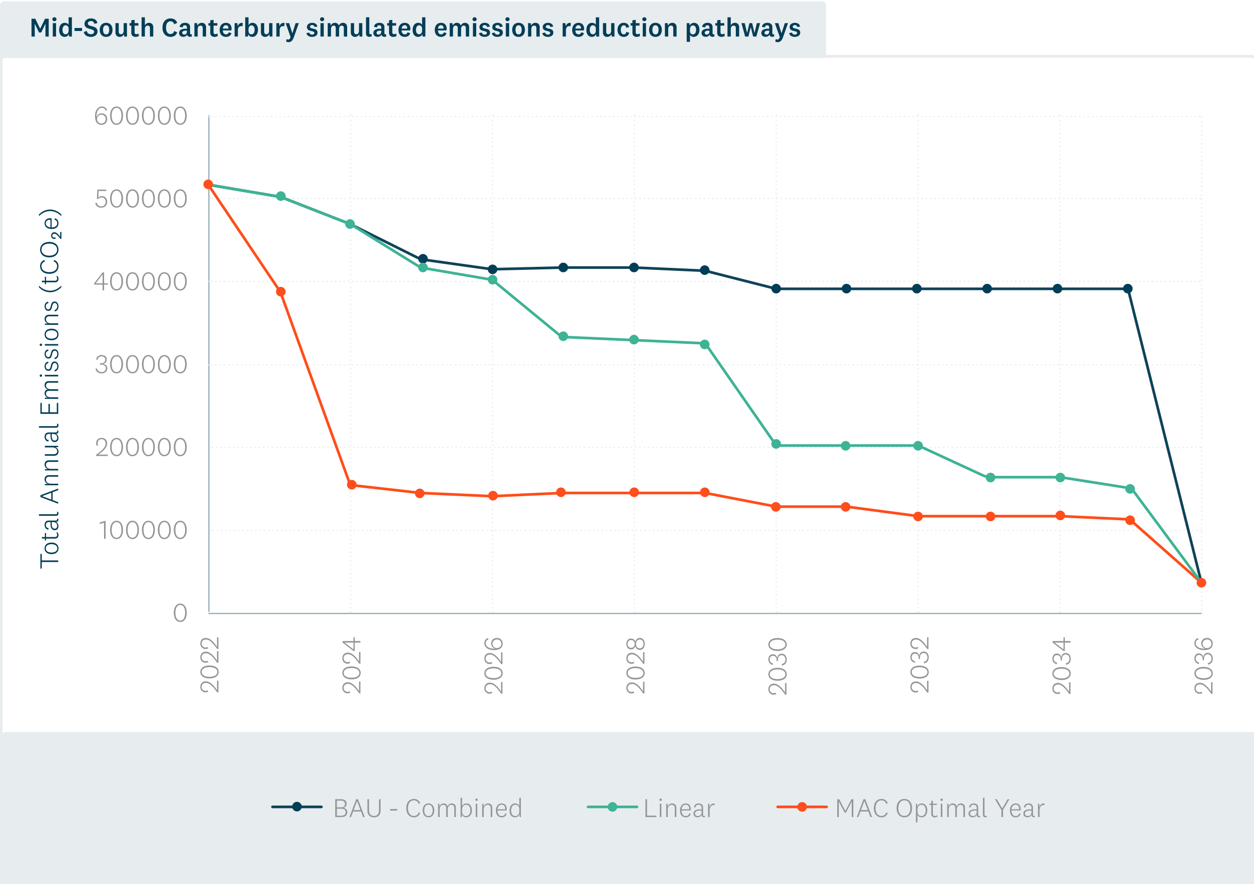
[135] There could be a range of ways this could be observed in reality. We suggest it could be thought of as organisations desiring to take a MAC Optimal approach, but being slowed by capital constraints, the effect of uncertainty, a more gradual emergence of biomass resources, and/or the realities of constraints on Transpower and EDBs ability to deliver network upgrades as a result of regulatory requirements, construction capacity etc.

[136] We use the Climate Change Commission's assumed future ETS prices (demonstration pathway) as our forecast of future carbon prices.

10.2.1 Pathway results

All pathways eliminate 93%[137] of process heat emissions in the region (a reduction of 504kt out of a total 542kt[138]), but at significantly different pace (Figure 47).

Figure 47 - Emissions reduction trajectories for different simulated pathways. Source: EECA



Using the assumed timings in the individual ETAs (or 2036 where unavailable) is the slowest decarbonisation path (BAU – Combined). Over 70% of the emissions reductions are assumed to occur in 2036.

[137] Remaining emissions of around 39,000t relate to Scope 2 emissions from electricity

[138] As outlined earlier, electricity is modelled to have a scope 2 emissions content of 100kg per MWh of electricity, per published guidance from the Ministry for the Environment on accounting for greenhouse gas emissions. Since the increase in electricity demand is approximately 550GWh, there is ~55tCO2-e resulting from this increase in electricity demand.

The MAC Optimal pathway decarbonises much quicker than either the BAU or Linear approach in the first two years. As indicated in Section 11.1.4, around 67% of emissions reductions would be economic in 2023[139], and 71% by 2024. The cumulative difference between the BAU approach, and MAC Optimal, is 3.4MtCO_2e – exclusively long-lived greenhouse gases– across the period 2022-2036.

Given the timing of this report, what the MAC Optimal assumes as achievable in 2023/24 is not realistic. That said, it does highlight that there are projects that, with co-funding, would be 'ready to go' in the very near future. As a number of these projects are electrification of process heat, it suggests that the constraints on progress are more likely to be securing network capacity.

10.3 Pathway implications for fuel usage

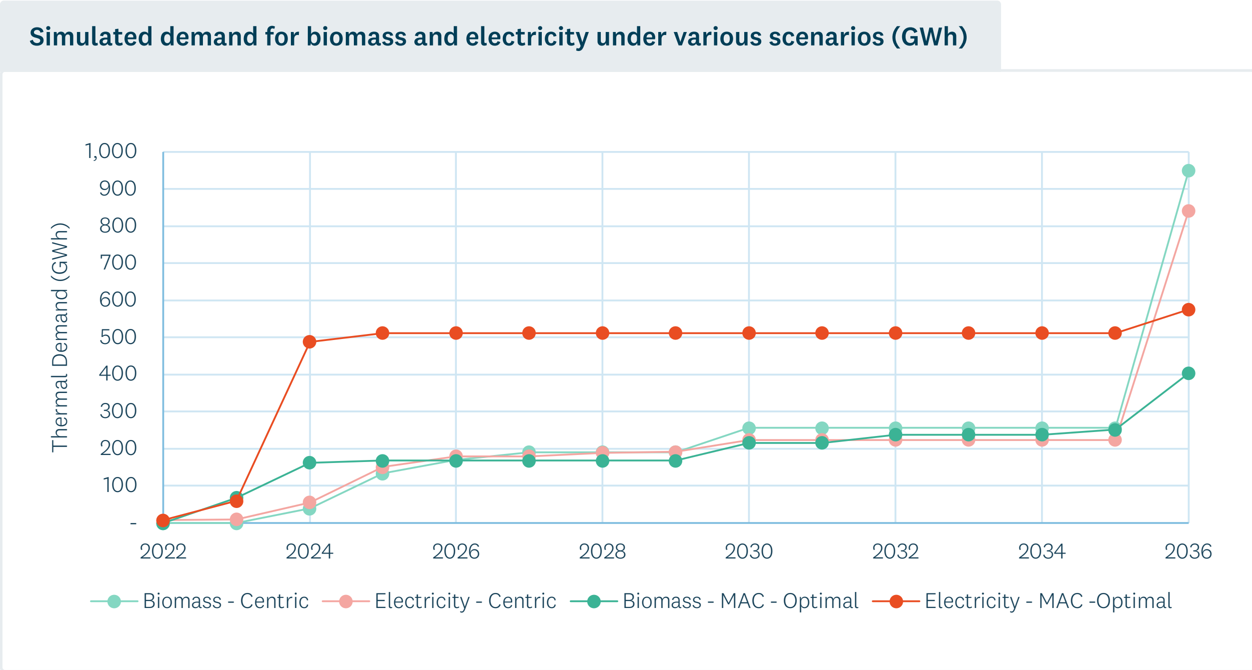
We can now compare the trajectory of demand for biomass and electricity arising from the various pathways. Below we compare the growth in demand in three of the pathways:

- BAU – Biomass Centric, Electricity Centric
- Linear
- MAC Optimal

As shown in Figure 48, the BAU – Centric pathways deliver the highest demand in 2036 for each fuel – 850GWh for electricity, and 950GWh for biomass. The pathways that use MACs to determine fuel switching decisions (table above) result in a more diverse set of fuel decisions, with around 40% of the energy needs supplied by biomass (with a consumption of 403GWh of delivered energy), and 60% of energy needs supplied by electricity (with 575GWh of delivered energy).

[139] As discussed in that section, using the average 10-year forward expectation of the CCC's pathway.

Figure 48 - Simulated demand for biomass and electricity under various RETA scenarios. Source: EECA



The pathways show that the growth of biomass demand is relatively consistent across the 2026-2035 period of the pathways, but electricity growth is accelerated early by the MAC Optimal approach.

We now consider the implications for each fuel in more detail.

10.3.1 Implications for electricity demand

Figure 49 shows the growth in electricity demand in each of the pathways.

Figure 49 - Growth in electricity demand from fuel switching pathways (unconfirmed RETA sites). Source: EECA

Growth in electricity demand under different simulated pathways (GWh)

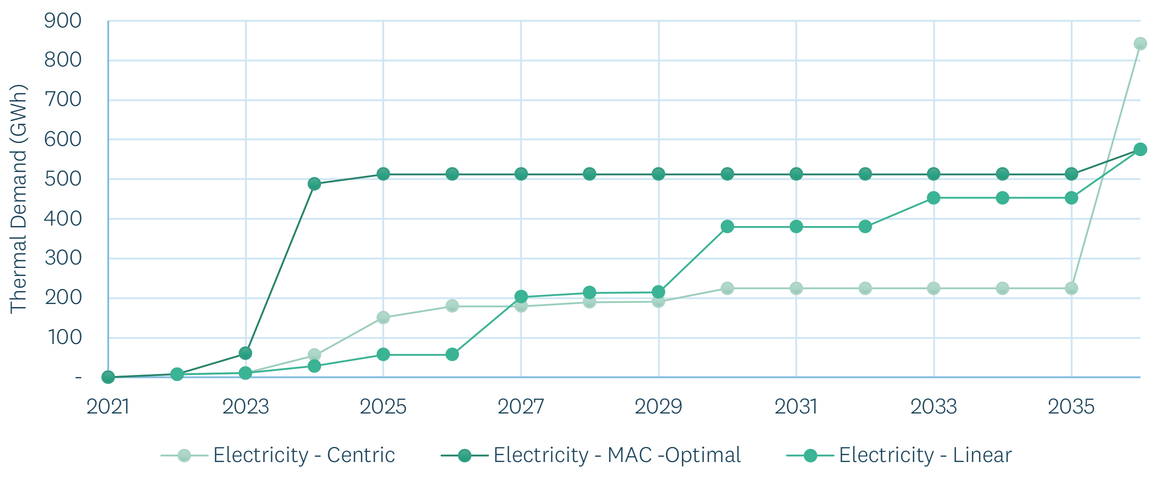
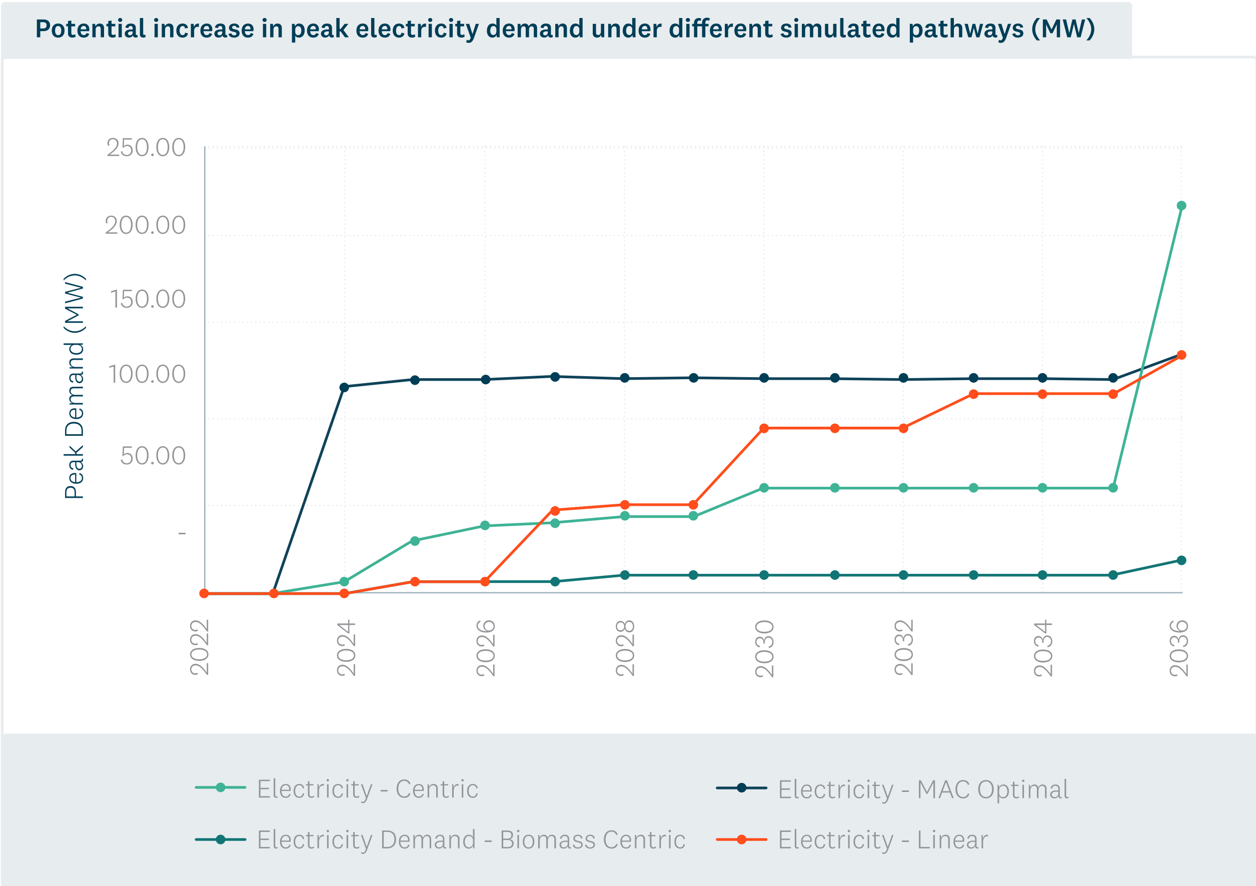


Figure 49 reinforces that the use of MACs to simulate decision making accelerates a number of significant electrification projects, thus achieving a much more significant growth in demand than the Electricity Centric pathway. As intended, the Linear pathway has a more gradual increase in demand.

A critical aspect of the growth of electricity for process heat is the impact it has on network planning. Networks will be more interested in the impact on potential peak demand than energy consumption per se. Figure 50 illustrates this, for each pathway.

Figure 50 - Potential peak demand growth under different pathways



Included in Figure 50, for completeness, is the electricity demand that would result from the Biomass Centric pathway. These represent the electrification projects that have either already been confirmed, or those where electricity is the only option (e.g. heat pump projects).

The difference between the scenarios through time – which reflects the degree of uncertainty faced by network planners– is quite significant. At any point in time, the peak demand from the electrified boilers could vary from 15MW (if a Biomass Centric world eventuates) to 120MW.

That said, we reinforce these contributions to peak network demand are upper bounds (in each pathway), as they assume that all electrified boilers reach their maximum consumption at the same time of day and time of year (i.e. coincident peak demand). This is a conservative assessment, as there is likely to be a diversity amongst peak demands as outlined in Section 9.4, as well as commercial incentives to shift this peak demand away from the time of the wider network peaks. Hence the impact of flexibility and diversity on capacity upgrades depends on a range of factors that need to be considered more fully.

10.3.1.1 EDB Analysis

The implications of these peak demand growth scenarios will be different for each of the distribution network companies, as their existing networks have different levels of spare capacity (as outlined above).

Section 9.3 highlighted that there can be material differences between adjacent networks in terms of unused capacity. These differences exist for a range of historical reasons. This can lead to quite different relative connection costs for projects connection in each region. While we showed the variability in individual connection costs in Figure 32, Table 19 shows how the connections potentially affect each EDB's network.

Table 19 - New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways

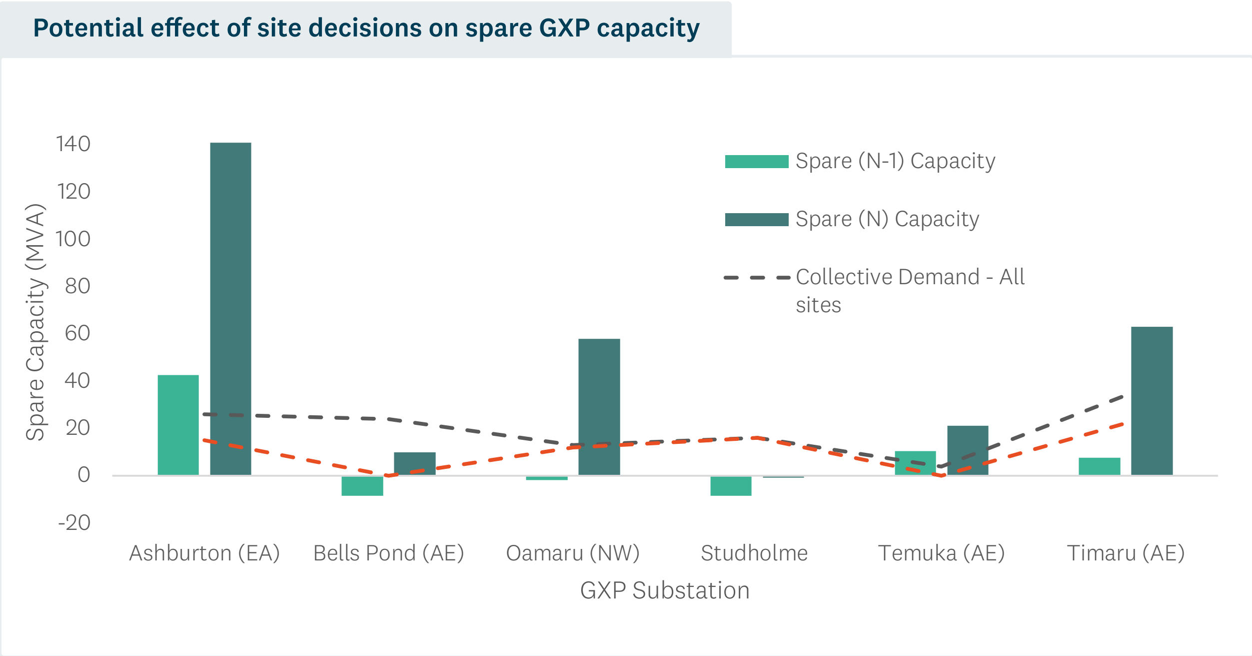
EDB	Electricity Centric Pathway		MAC Optimal Pathway	
	Connection Capacity (MW)	Connection Cost ($M)	Connection Capacity (MW)	Connection Cost ($M)
EA	29	$5.38	15	$3.77
Alpine	76	$16.48	38	$6.54
Network Waitaki	13	$4.85	12	$4.85
Transpower	91[140]	$51.90	91	$51
Total	**209**	**$78.61**	**154**	**$65.75**

Table 19 shows that Alpine Energy will experience the largest relative increase in process heat-related electricity demand, irrespective of whether the Electricity Centric or MAC Optimal pathway results. The connection cost estimates suggest that between $66-$79M will be spent by process heat organisations connecting their new plant to either Transpower's or the EDB's networks, depending on the pathway.

Figure 51 adds the MAC Optimal pathway to Figure 33 (which assumed all sites switched to electricity). It suggests that, if all MAC Optimal electrifying organisations peak together, and at the same time as the wider network peaks, then Oamaru, Studholme and Timaru GXPs will exceed their current N-1 ratings at peak times. But, as shown in Section 9.4, this may not be true once the diversity in demand profiles is taken into account.

[140] Fonterra converting all four boilers at Clandeboye to electric. Ergo's analysis showed that the only practical way to do this was to divert the load from Alpine's network and connect directly to Transpower's grid at Orari. Technically, this would result in a small reduction in Alpine's peak demand (resulting from the disconnection of Fonterra's current electricity demand), but we do not have data on what that is.

Figure 51 - Potential effect of site decisions on spare network capacity: Electricity Centric and MAC Optimal pathway



This does not necessarily mean that Transpower must commit to the estimated $51M of grid upgrades outlined in Section 9.3[141]. As outlined in that section:

- The natural diversity between the demand profiles of the six organisations electrifying in the MAC Optimal pathway is likely to result in the combined increase in peak GXP demand being less than the simple addition of their demands that is shown in Figure 51. Section 9.4 demonstrated a 16% lower impact on Timaru GXP demand compared with simply adding the peak demands of each individual site.
- These organisations may be able to enable significant flexibility in their usage, such that they can avoid consuming significant electricity at peak times.
- The organisations may be willing to take a lower security standard through, for example, a special protection scheme (SPS), which would see their supply interrupted on those rare occasions where a grid failure event occurred.

The overall impact of these three approaches may result in these upgrades, totalling $51M, being deferred[142].

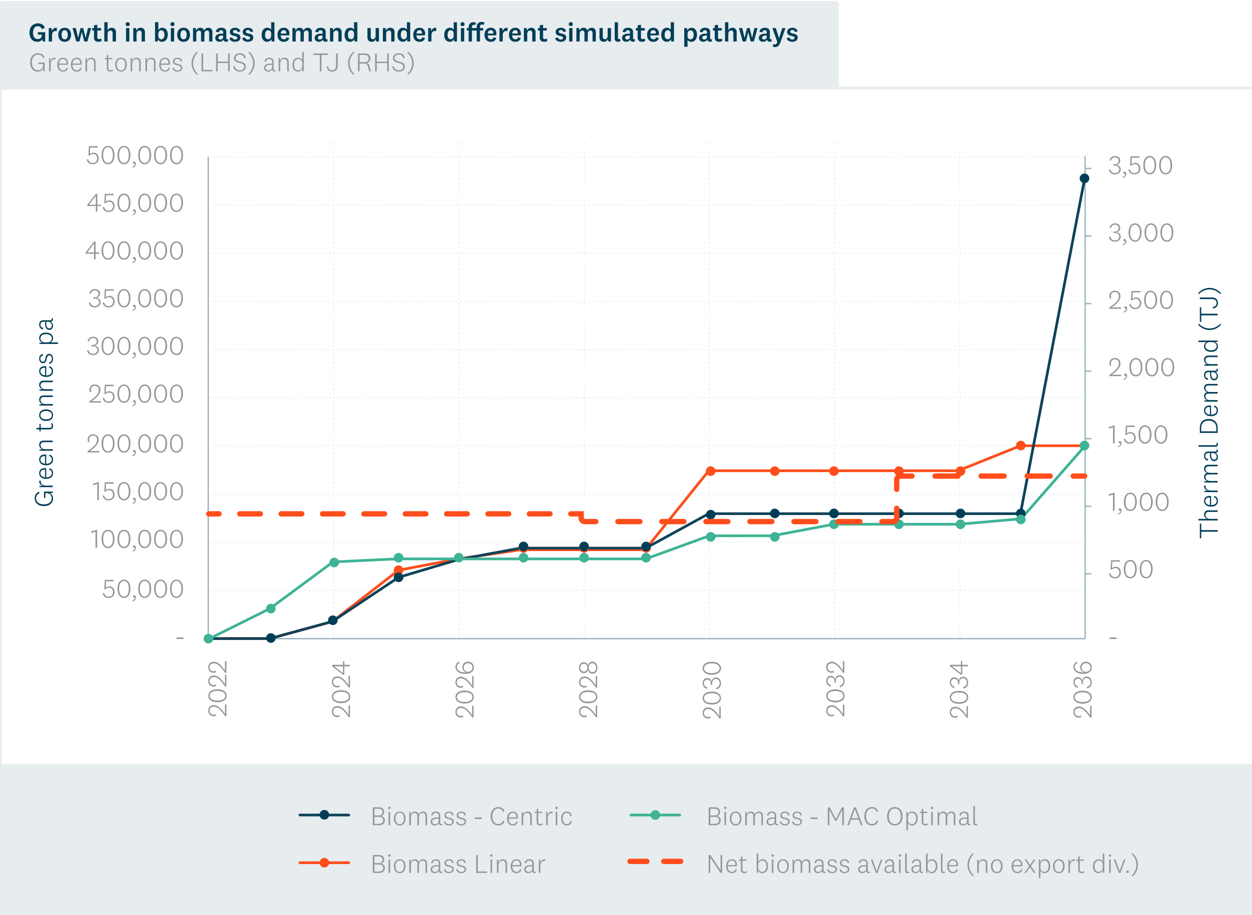
[141] $35M for a new North Otago GXP, serving both Oamaru and Studholme, and a $16M upgrade of Timaru.

[142] This depends on the degree to which wider demand growth in these networks are also driving the need for an upgrade.

10.3.2 Implications for biomass demand

Figure 52 shows the growth in biomass demand (in both GWh and TJ per annum) arising from each of the pathways. The MAC Optimal pathways result in less than half the final demand from the Biomass Centric pathway, and the co-funding sees a modest acceleration of demand growth, bringing forward around 25% of demand from 2025 to 2023.

Figure 52 – Growth in biomass demand from pathways. Source: EECA



We can also see that by 2029, the estimated volumes of unutilised harvesting and processor residues (after existing bioenergy demands are removed[143]) will be exhausted under all three pathways. This is shown as the red dashed line in Figure 52. Note that these resources include in-forest residues from the cutover, which may be difficult and costly to extract. Meeting the remaining demand from fuel switching projects after 2029 will require other resources, as identified in Section 8.4.2.

[143] See Section 7.5

10.4 Sensitivity analysis

EECA acknowledges that there are a range of factors which determine each organisation's final decision on fuel switching. The Net Present Value of a project (at the expected carbon price) is only one factor, albeit an important one for owners and shareholders. However, capital constraints, competing priorities, risk appetite, uncertainty about future costs, supply chain constraints and labour market implications are examples of the myriad factors that must be taken into account when deciding when to switch away from fossil fuels, and which fuel to choose.

This report does not speculate on those factors. However, understanding how sensitive the fuel choice is to the commercial factors may go some way to providing confidence of the best decision, both in terms of fuel choice, and timing.

This RETA report has outlined some of the uncertainties related to both up-front and ongoing fixed and variable costs, for example:

- The uncertainty in the underlying variable fuel costs (electricity and biomass). Electricity has a combination of fixed (per-annum use-of-network charges) and variable costs.
- The uncertainty regarding the magnitude of up-front upgrade costs required to connect an individual RETA site to the electricity network (including the degree to which flexibility in plant consumption could reduce these costs).
- The uncertainty in the quantity of sustainable biomass that could be practically brought to market and made available as a source of bioenergy.

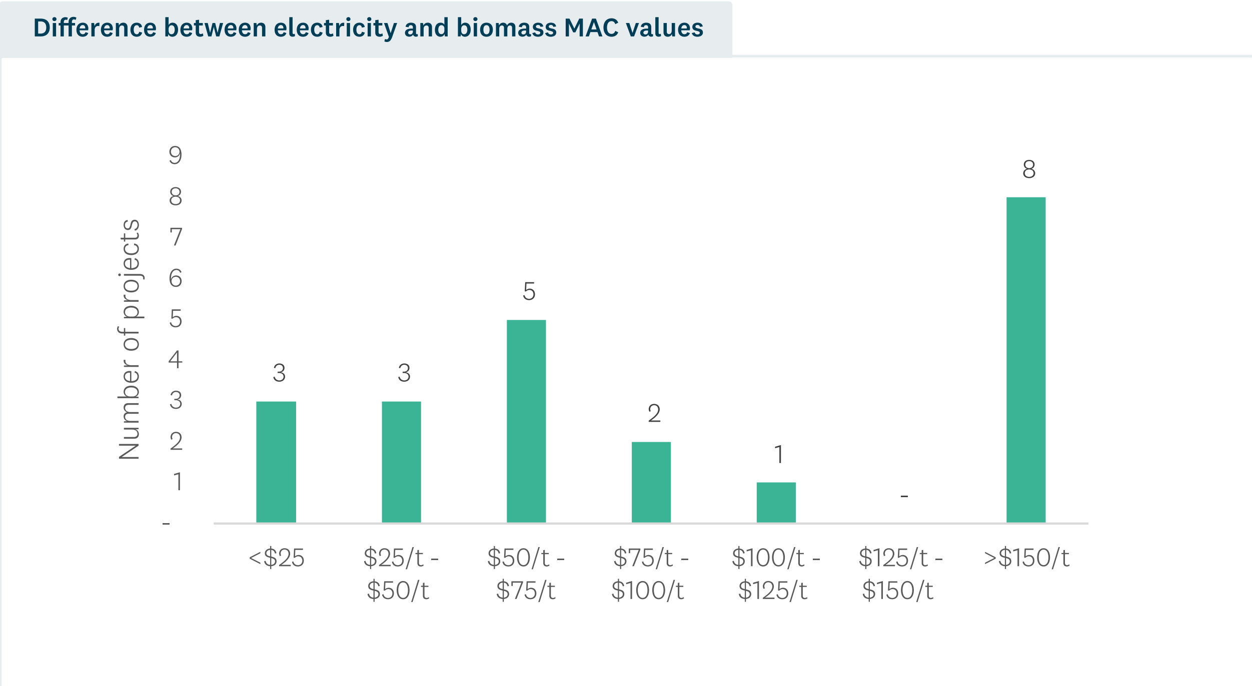
In terms of fuel switching, one way to consider how sensitive the fuel switching decision is to variability in underlying costs is to look at how close the MAC values for the competing fuels.

For the 22 RETA sites where both electricity[144] and biomass[145] is being considered, Figure 53 shows that nine projects have differences between electricity and biomass MAC values of over $100/t. It would take a considerable change in underlying costs to change the optimal fuel decision.

[144] Including 4 heatpump projects where heatpumps could supply the site's whole process heat needs.

[145] Including biogas (1 project)

Figure 53 - Difference between electricity MAC value and biomass MAC value; sites that are considering both options (n=22). Source: EECA.



If, for an individual project, the biomass and electricity MAC values were very close, plausible deviations from EECA's input estimates used in this analysis could change the decision. Figure 52 shows there are 6 projects where the difference in MAC values is less than $50/t. To illustrate the sensitivity of these MAC values:

- A 20% change in up-front capital costs (including network upgrade costs) can change the MAC value by between $8/t and $60/t for either electricity or biomass.
- A change in ongoing network charges of 20% could change the MAC value by between $10/t and $60/t for most projects, with an average of $25/t.

Hence it is plausible that these changes could alter the relativities of the two fuels, and change the optimal timing.

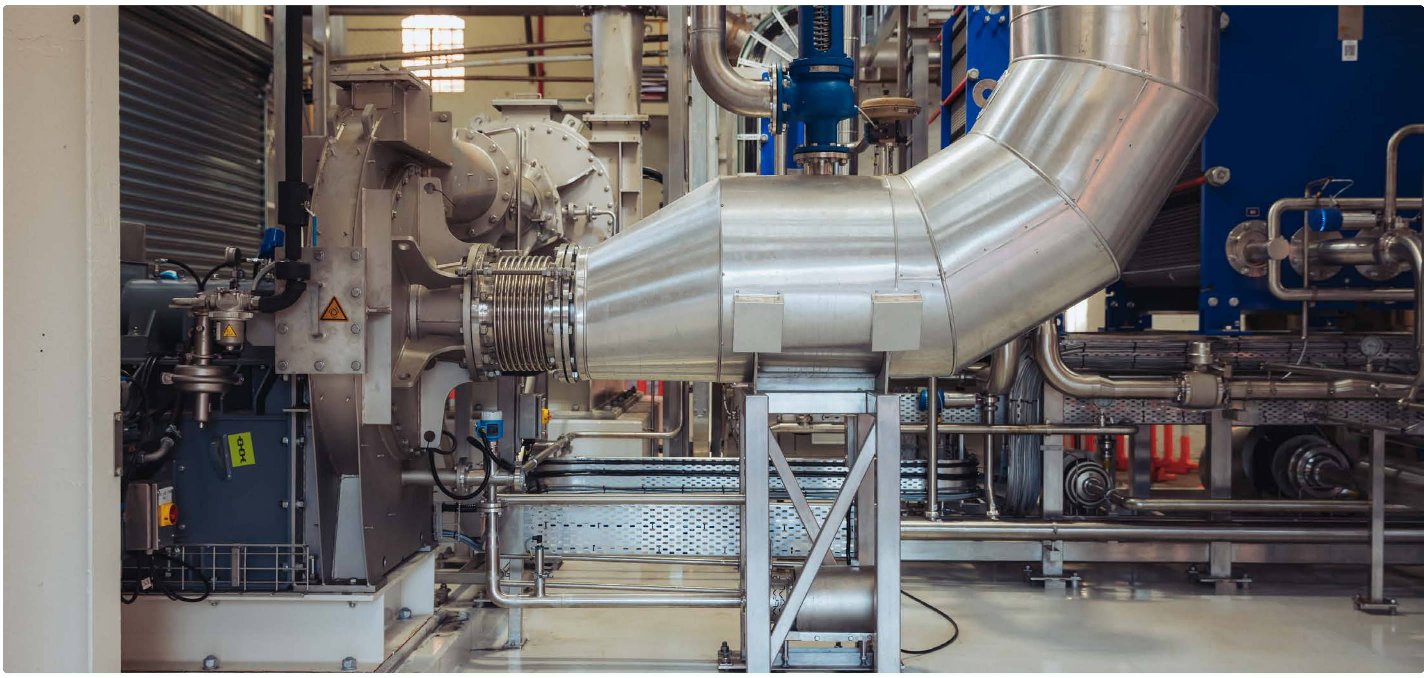
The scenario decision makers need to consider are not purely financial. For example, a restriction in the availability of sustainable biomass may arise, meaning organisations who commit to decarbonisation late in the RETA period are only able to electrify.

To test the impact of potential changes on the pathways, EECA undertook the following four sensitivities:

- Amending the MAC Optimal pathway to include acceleration co-funding from the GIDI fund. GIDI co-funding has been applied to projects in a consistent manner.
- The use of EnergyLink's 'Low' price scenario, from Section 9.2.2.1, to drive the price of electricity.
- An assumption that Fonterra uses biomass to fuel two Clandeboye boilers coupled with a limitation on biomass availability to 1,700TJ (472GWh). The limitation removes A-grade and pruned logs from the analysis in Figure 13.
- Amending the decision criteria for the timing of a decarbonisation investment, from when the average of the 10 year carbon price forecast exceeds the MAC, to when the current year carbon price exceeds the MAC (as discussed in Section 11.1.2).

An additional modelling of optimal decisions was conducted using TIMES-NZ. TIMES-NZ is an optimisation model of the whole energy system (in this case, just the Mid-South Canterbury region) and is thus able to optimise individual process heat user decisions based on available biomass and electricity supply and costs. This is a slightly different approach to our MAC-based analysis. The results are in Appendix B. Notably:

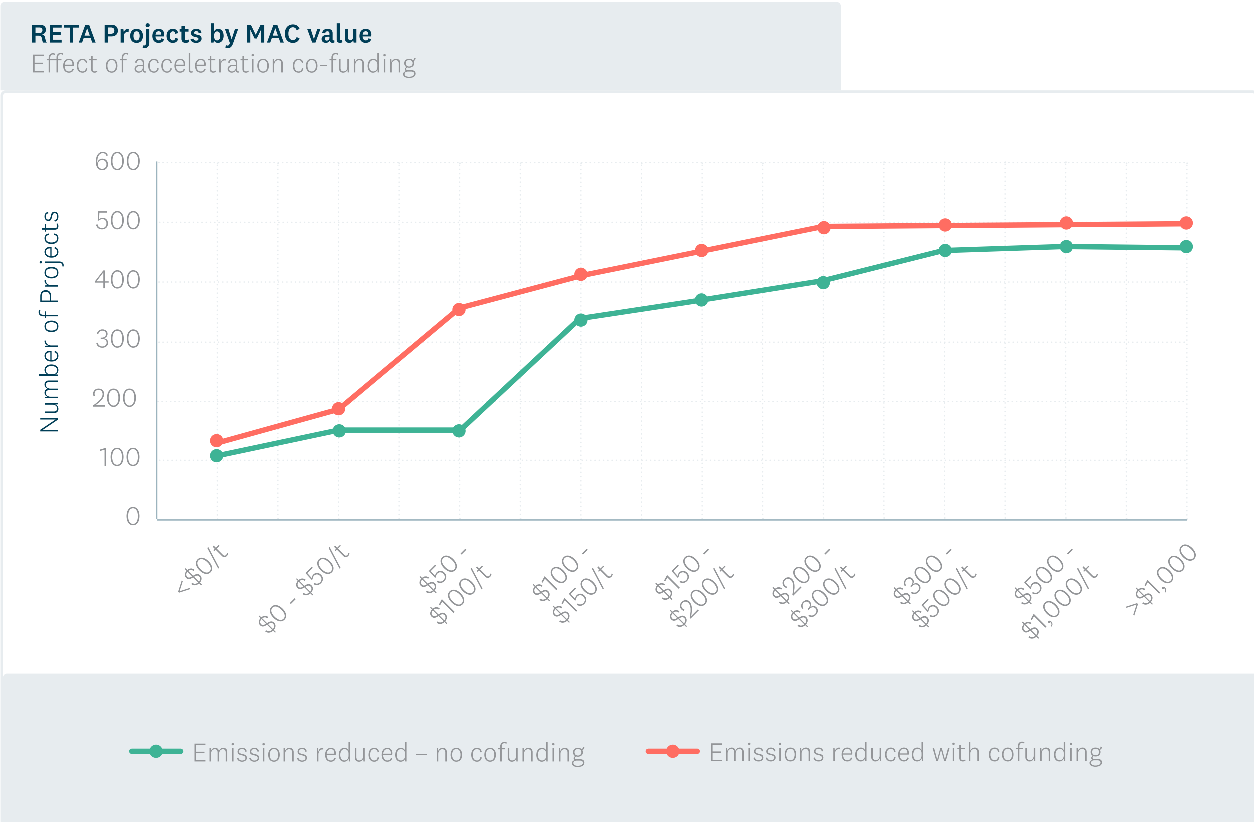
- The model achieves emissions reductions at a similar pace to our MAC-Optimal pathway.
- The model results in slightly more even sharing of energy requirements, with 55% of fuel requirements switching to electricity, and 45% to biomass.



10.4.1 Acceleration co-funding

The effect of simulated government GIDI co-funding on the fuel switching MACs is illustrated in Figure 54.

Figure 54 - Range of MAC values and cumulative emissions reductions with co-funding – fuel switching only. Source: EECA



The effect of acceleration co-funding is to lower the MAC values of a number of projects - Figure 54 shows that the quantity of emissions reduced for less than $\$100/tCO_2e$ is more than doubled. This is significant, especially because these projects would be economic today if investors believed that the Climate Change Commissions forward pathway of carbon prices was to be achieved. Co-funding accelerates decarbonisation.

MACs are only one measure of how a process heat organisation will make a decision with respect to the timing of its decarbonisation investment – the degree to which – over the long term – the investment will lead to a better outcome for the business. But the investments contemplated in Figure 54 involve significant up-front funding requirements. While many businesses have access to the commercial financing products needed to fund decarbonisation projects, most have constraints on the amount they can borrow from these sources, leading to competition for limited pools of internal capital. Decarbonisation projects are often deprioritised due to less attractive internal rates of return than other projects, or because decarbonisation is considered a lower priority than, for example regulatory compliance, or investing in expanded production.

Hence the impact of co-funding on MACs alone only tell part of the story. The presence of decarbonisation co-funding may overcome these wider constraints, even if it has a relatively small effect on the project's economics. Even projects that appear to be economically efficient may not occur (or not occur quickly enough) without an injection of government support.

10.4.2 Lower electricity prices

As highlighted by EnergyLink (and discussed in Section 9.2.2.1), there are a range of factors that could lead to electricity prices that are materially different to its 'central' scenario used for the analysis in this chapter. Figure 55 shows the impact of EnergyLink's 'low' price scenario on MAC values.

Figure 55 - Impact of EnergyLink's electricity price 'Low Scenario' on MAC values

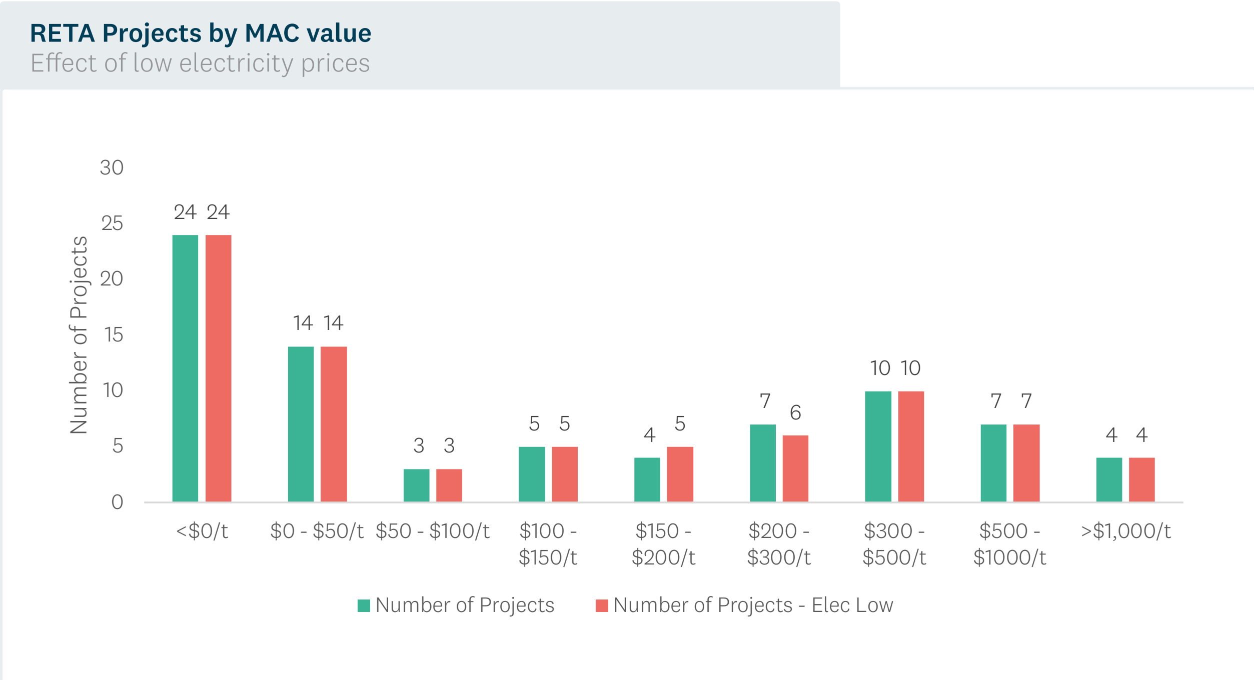


Figure 55 shows that lower electricity prices has the effect of shifting one project from a MAC value from the $200/t-$300/t category into the $150/t-$200/t category. However, the somewhat coarse granularity of Figure 50 disguises that it has changed a number of project MACs – just not by a sufficient amount to shift them between MAC categories in the chart. Across the 17 projects that did have their MAC values lowered, the change was between $8/t and $20/t (around 5% on average).

The relatively small effect is largely due to the use of a market-based retail tariff in the first 10 years of the project that was lower than EnergyLink's price forecast. Hence a sensitivity analysis that used a different EnergyLink scenario only changed the second 10-year period of the MAC calculation. The impact of this latter period on the MAC value will be significantly muted by present-value discounting.

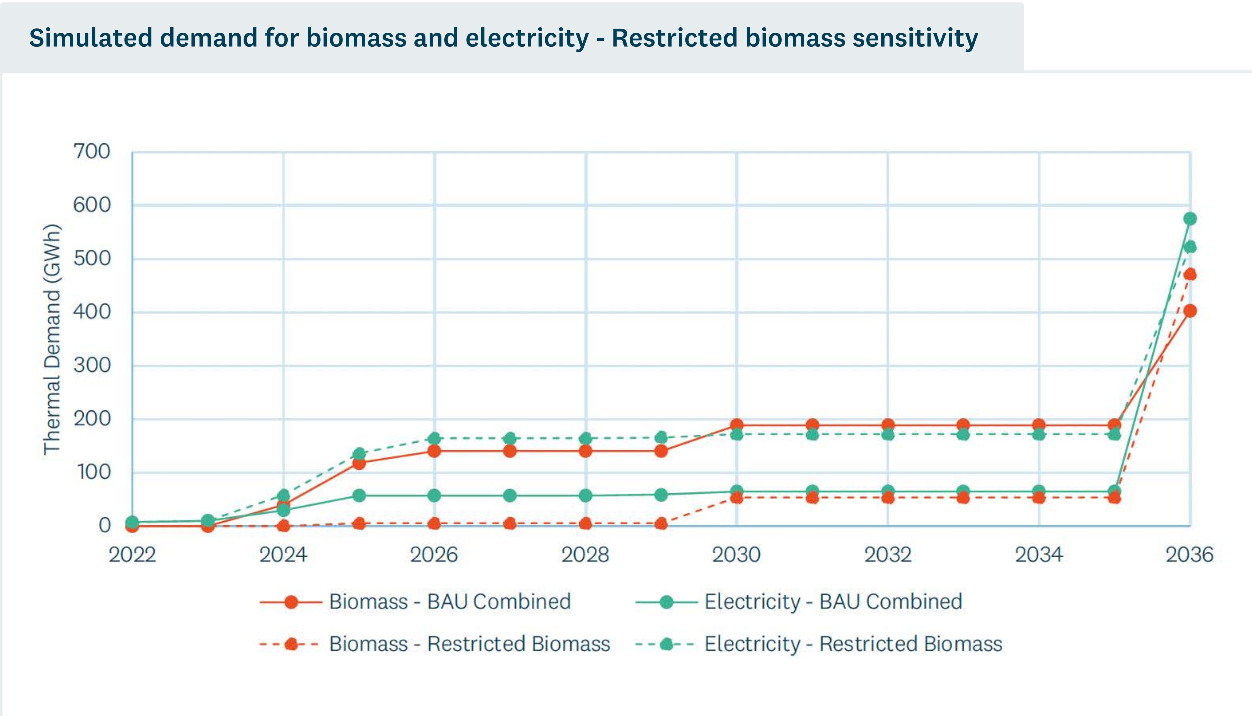
10.4.3 Large boiler conversion to biomass and limitation on resources

In Section 8.6 we presented the overall availability of woody biomass as a boiler fuel in Mid-South Canterbury. There, we highlighted that it was very unlikely that A-grade and domestic pruned wood would be diverted to bioenergy. Additionally, we showed the existing level of demand for woody biomass as a source of bioenergy. Hence, a more realistic (and less disruptive) scenario would be to remove A-grade, domestic pruned, and existing bioenergy demand from the available biomass resources.

Additionally, the MAC-based analysis above suggests that Fonterra would select electricity as the fuel for its four Clandeboye boilers. However, Fonterra has stated a general preference for biomass as a fuel[146]. Whichever fuel Fonterra chooses, it will have a large impact on the supply-demand balance for that fuel. Hence we test the more realistic resource availability outlined above, but also assume that two of Fonterra's boilers use biomass.

The resulting effect on the pathway is illustrated in Figure 56. Compared with the BAU Combined pathway, the combination of a 341GWh increase in biomass demand and lower resource availability results in a much lower use of biomass until 2036 (when the Fonterra boilers are assumed to convert to biomass). The quid pro quo is that a number of projects that chose biomass in the BAU pathway now must use electricity to decarbonise, due to the scarcity of the biomass resource.

Figure 56 - Restricted biomass pathway vs BAU Combined (GWh)



[146] Fonterra (2021), Submission to Climate Change Commission 2021 draft advice to government

10.4.4 Amending the decision criteria for investment timing

This sensitivity compared the demand for biomass and electricity under two decision making criteria – the 10-year future average carbon price (used for the MAC Optimal pathways above) versus simply waiting for the present-day carbon price to exceed the MAC value of the project.

Figure 56 - Comparing MAC-based decision making criteria

The 'current year' criteria leads to approximately four-year delays in a number of projects. This is a result of the CCC's carbon price scenario increasing through time; hence a forward-looking 10-year average will always be higher than the present-day carbon price, and will thus trigger investments earlier (all other things being equal).

Wairakei Geothermal Power Station - Taupo, New Zealand

11 Insights and recommendations

The RETA aims to develop an understanding of what is needed to decarbonise a region through a well-informed and coordinated approach. The focus is to understand unique region-specific opportunities and barriers when developing regional energy transition roadmaps.

This report has considered a number of organisations facing the decision of how to reduce their fossil fuel process heat consumption.

The aim of this report, which is the culmination of the RETA planning stage for the Mid-South Canterbury region, is to:

- Provide process heat users with coordinated information specific to the region to make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure.
- Surface issues, opportunities and recommendations.

The report is premised on the observation that, while individual organisations may be able to obtain information pertinent to their own decarbonisation decision, some of the most important factors require a collective, regional view. Only with a regional view can 'system-level' challenges and opportunities be evaluated. If these challenges can be addressed, and opportunities pursued, process heat consumers and fuel suppliers can make better decisions.

This report has illustrated a range of decarbonisation pathways, all of which demonstrate how the combined decisions of a range of process heat users may lead to common infrastructure challenges from a supply perspective. The pathways illuminate different decision-making frameworks that might be used by process heat organisations to decide on which fuel to switch to. Hence the pathways give a sense of the diversity of outcomes that might be expected.

In this section, we will present our findings from the work undertaken and recommendations about how the identified challenges can be resolved.

A ‘whole-of-system' perspective would go further than this RETA to incorporate other sectors. The transport[147] sector will, in all likelihood, decarbonise through a combination of sustainable fuels (including bioenergy and electricity), and in some situations process heat and transport will compete for the same sources of fuel. The nature of the decarbonisation technologies that underpin these decisions is changing quickly, and a system-level view – even at a regional level – will allow decision makers and policy makers to be able make informed choices and identify challenges, gaps and opportunities. This makes a RETA more complex, but more insightful in identifying system challenges and solutions.

11.1. Biomass – insights and recommendations

The analysis above shows that comprehensive extraction and conversion of estimated processor and harvesting residues (after the deduction of the existing consumption of these residues) has the potential to supply 80% of the MAC Optimal pathway biomass demand and 30% of the Biomass Centric demand. It will need to be supplemented by wilding pines or diverted low-grade export wood to meet our modelled biomass demand, noting that in all scenarios residues are sufficient until much later in the 15-year period.
This has highlighted the following challenges and opportunities:

Reliance on residues: Cutover residues may be more complex and more expensive to recover than modelled here. There appears to be scant data available to be more definitive about the potential here. There are a number of opportunities this gives rise to, including:

- More analysis – and potentially pilots – are required to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering cutover residues.
- In tandem, work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.
- Work with Port Blakely to share their learnings regarding collection, storage and use of residues for bioenergy.
- Analysis is also required to determine the impact of recovering these residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.

Beyond residues: It seems clear that more than just residues are likely to be required to satisfy biomass demand.

- Develop national guidance or standard (based international experience tailored to the New Zealand context) regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.
- Assess the potential demand for wood pellets in the region, and encourage local development of wood pellet manufacturing capability accordingly.

[147] The analysis presented in Section 8.3 included some proposed public charging infrastructure for electric vehicles.

Competing uses: There will likely be competition for biomass from other sectors.

- More in-depth analysis of competing uses of biomass for energy at a national and regional level could help future RETA studies understand the significance of these competitive pressures. It would also help the process heat decisions where transport emissions may factor into decisions about securing biomass supplies.

Confidence in long-term volume and price: The uncertainty in future biomass volumes and costs may hamper the ability for organisations to commit to biomass boiler investments prices. Securing long-term contracts with biomass suppliers will be key to confidence in making fuel switching (boiler conversion or replacement) decisions.

Mechanisms should be investigated and established to help facilitate efficient price discovery, for example:

- Regular (e.g. annual) updates to the biomass analysis in this RETA.
- Encourage use of industry-standard long-term contracts for process heat service-level biomass supply[148].
- Greater transparency about (anonymised) prices and volumes being offered or traded.

12.1 Electricity – insights and recommendations

Electricity has a more established delivery infrastructure, and a vibrant market for securing medium-term supply of electricity at relatively stable prices through retail contracts.

There are, however, a range of uncertainties about the longer term cost trends across the supply chain – generation, transmission, distribution and retail. Improvements in sharing information, data, and intentions between these parties needs to be a high priority. Process heat users will make the best decarbonisation decisions if they clearly understand the potential costs and how enabling flexibility in their consumption will help reduce those costs. Transpower and EDBs can only make the best decisions about upgrades if they have the best information about process heat organisations' intentions, and realistic levels of flexibility that process heat organisations can offer.

This RETA has sought to increase the level of information shared, but we acknowledge that the world is changing quickly and this needs to be a continued process. During the course of developing the Mid-South Canterbury RETA, we were struck by how fast the landscape is changing for the electricity industry. The more up-to-date information is, the better able organisations are to adapt to a changing world. Electricity industry participants need to find ways to increase the pace of information exchange.

[148] See https://www.bioenergy.org.nz/documents/resource/Technical-Guides/TG06-Contracting-to-deliver-quality-wood-fuel.pdf for a guide developed by the Bioenergy Association to assist the sellers and purchasers of solid biofuels trade and contract these materials for the production of energy.

11.2.1 The role we need EDBs to play

Given the pace of change, EDBs need to proactively engage with process heat users in order to:

- Stay abreast of process heat users' intentions regarding timing of electrification decisions. This will enable EDBs to accommodate their intentions in their network plans and make efficient use of network resources.
- Provide process heat users with timely advice and a good understanding of network investment, and network security levels, that can be incorporated into process heat business cases.

A related opportunity is for the network companies to provide a stronger coordinating function for each region's large electrification initiatives. This RETA has accelerated a range of discussions between Transpower, EDBs and large process heat users – this should become the norm.

Similarly, we recognise that the regulatory framework for network companies may not support pragmatic, sensible investment decisions. While we have not investigated the potential for regulatory change, we endorse change if it helps accelerate decarbonisation, and see opportunity Transpower's renewable energy hub concept if it were expanded beyond the supply-side to include the demand-side.

Finally, we ask EDBs to investigate how they could equitably pass on, to electrifying process heat users, the benefit of the eight-year delay in experiencing the full residual cost component of the TPM associated with an increased demand.

11.2.2 Information process heat organisations need to seek from EDBs and (where relevant) Transpower:

- **The risks and cost trade-offs of remaining on N security relative to N-1 (or N-0.X if available).** The EDB will have sufficient history of network outages to provide a realistic expectation of the frequency of network interruptions, as well as the duration of any interruption to supply.
- **A clear process, timeframes and information required for obtaining network connection[149].** These processes should have realistic timeframes and the nature of the information that each stage of the process will provide the process heat user, and the data and information network companies need from the process heat user at each stage (see below).
- **Network charges and network loss factors relevant to their connection location.** As outlined in Section 9, we have estimated an average level of network charges across the three EDBs involved in this Mid-South Canterbury RETA, but the network charges for any individual process heat customer will depend on their particular location.

[149] Transpower's web-based guide to the connection process is a good example. See https://www.transpower.co.nz/connect-grid/our-connection-process

- **What their likely electricity consumption means for network upgrades.** The screening-level estimates provided in Section 9 provide a starting point, but more detailed discussions and engineering studies are required to firm these up. An important piece of information here is how the process heat user's demand (see below) aligns with existing demand patterns on the relevant parts of the network.

- **How flexibility in their electricity consumption and/or the level of network security they desire could impact the cost of connecting them to the network.** Like network charges and loss factors, the degree to which Transpower and EDBs can be flexible with network security and therefore the extent of network upgrades required depends on the connection location.

- **How upgrade projects could be accelerated, for examplethrough:**
  - Early and bulk procurement of critical long lead time equipment (items such as transformers, switchboards, cable, conductors etc).
  - Consideration of expedited delivery (often suppliers will expedite for a premium or offer air freight options.
  - Paralleling design and build activities where possible to reduce durations.
  - Using commercial levers in contracts to expedite (e.g. delivery incentives or similar).

11.2.3 Information process heat organisations need to seek from electricity retailers:

- **What tariffs they offer which lock on a fixed set of prices over multiple years.** This avoids process heat organisations being exposed to unexpected price rises.

- **What tariffs they are offering that reward process heat organisations for using flexibility in their electricity consumption.** While retailers will be able to provide tiered pricing (e.g. different prices for peak periods vs off-peak periods), they should be developing more sophisticated arrangements which can lower their wholesale costs, the benefits of which should be shared with organisations who provide them flexibility. This should include tariffs which give the process heat user more exposure to the underlying wholesale price, but retailers need to explain the nature of the risks of operating under such a tariff.

11.2.4 Information that process heat users need to provide retailers, EDBs and (if relevant) Transpower:

In order to obtain good advice, process heat users need to develop and share a good understanding of:

- The nature of their electricity demand over time (baseload and varying components), especially what time of day and time of year their demand is likely to reach its maximum level.

- The flexibility in their heat requirements, which may allow them to shift/reduce demand, potentially at short notice, in response to system or market conditions.

- The level of security they need as part of their manufacturing process, including their tolerance for interruption.

- Any spare capacity the process heat user has onsite.

11.2.5 The need for electricity industry participants to encourage and enable flexibility

This RETA has highlighted some situations where costs could be significantly reduced if process heat users enable flexibility.

However, New Zealand is currently lagging other electricity jurisdictions (e.g. the UK) in establishing a mature set of arrangements where electricity consumers can, if they wish, provide their consumption flexibility to electricity industry participants, and share in the benefits that flexibility creates. This lowers the costs of electrifying new process heat.

Part of these benefits stem from the wholesale market, which creates the wholesale prices used to calculate electricity purchase costs incurred by retailers and large consumers who connect directly to the national grid. A future electricity system, with a higher penetration of renewables, will experience greater benefit from demand-side flexibility. It is likely that the retail market will evolve to reward customers who are able to respond dynamically. This does not necessarily imply that customers need to be fully exposed to wholesale prices. Customers may be able to remain on a stable retail contract, but one that has a lower tariff as a quid pro quo for assigning some degree of control over demand to an intermediary.

Practically speaking, this means that process heat users who are considering electrification should take the following into account:

- If there is flexibility in network security, process heat users should consider the degree to which their own loads could be modified (e.g. time-shifted through use of water storage) to accommodate network constraints, and/or quickly interrupted in the event a failure of a network component occurred.
- In principle, there are potentially significant benefits in having flexibility in their electricity demand (e.g. through maintaining a backup fuel/boiler system) that can respond to extended periods of electricity market stress (e.g. resulting from prolonged periods of low hydro inflows, sunshine or wind). That said, there are a number of logistical matters that would have to be considered to implement this, which EECA has not analysed.

For process heat users to be able to assess the benefits of process flexibility, they will need an improved level of information from electricity industry participants. EECA recommends better and more transparent information be published by EDBs, retailers, and the Flex Forum about the benefits to process heat users from enabling flexibility in consumption, and the types of commercial arrangements (between electricity consumers and retailers/EDBs) that should exist to provide these benefits[150].

[150] We note that, in its recent "Price discovery in a renewables based electricity system – options paper" the Electricity Authority's Market Development Advisory Group has included a preferred option C13 that recommends "Provide info to help large users with upcoming DSF investment decisions". See https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf, page 64.

11.3 Pathways – insights and recommendations

The pathways provided in this report illustrate how different assumptions about how and when process heat organisations make decarbonisation decisions can impact the resources and networks that provide the fuels.

While the pathways have their limitations, and EECA will continue to enhance these in future RETAs (e.g. through more sensitivity analysis), they have illustrated the uncertainty faced by biomass and electricity suppliers. A lot of this uncertainty relates to the timing of decarbonisation decisions by the RETA organisations, and thus speaks to the pace of demand growth. Specifically:

- Some pathways saw sufficient growth in the next five years that could result in progress being slowed by supply availability (biomass resources or network capacity). Given the likely lead times of bringing new biomass resources and/or network capacity to market, it suggests that **planning by forest owners, aggregators, and network companies needs to begin immediately, including the types of information sharing highlighted above.**
- The pathways highlighted that the extent to which process heat users are aware of, and incorporate, expectations of future carbon price trajectories into their decision making will have a significant effect of investment timing. Rigorous, publicly available long-term scenarios of carbon prices, and guidance for how process heat organisations can incorporate these into investment decisions, appears scant. **Ministries such as the Ministry for the Environment need to work with reputable organisations to develop carbon futures markets scenario-based forecasts that decarbonising organisations can incorporate into their business cases.**
- The pathways also demonstrate how government co-funding could potentially accelerate decarbonisation of Mid-South Canterbury process heat. **EECA encourages process heat users to enquire about government co-funding where the economics of decarbonisation are challenging; where they are economic, EECA encourages organisations to explore the potential for acceleration.**

Other than public EV charging infrastructure, the pathways do not incorporate the potential for the growth in bioenergy and electricity for transport to compete with process heat. EECA will continue to develop the analysis to incorporate this in future analyses.

11.4 Summary of recommendations

In summary, our recommendations are:

- **More analysis, and potentially pilots, should be conducted to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering harvesting residues.**
- **Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.**
- **Analysis is required to determine the impact of recovering harvesting residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.**
- **Development of national guidance or standard (based international experience tailored to the New Zealand context) regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.**
- **More in-depth analysis of competing uses of biomass for energy at a national and regional level could help future RETA studies understand the significance of these competitive pressures.**
- **Each RETA analysis should be updated in a brief, standardised format every two to three years, to ensure all organisations who support or participate in the decarbonisation of process heat have access to good, evidence-based insights.**
- **Mechanisms should be investigated and established to help suppliers and consumers to see prices and volumes being traded and have confidence in being able to transact at those prices for the volumes they require. These mechanisms could include standardised contracts which allow longer-term prices to be discovered, and risks to be managed more effectively.**
- **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**
- **EDBs should proactively engage with process heat users to understand their intentions, and help process heat users obtain a greater understanding of required network upgrades, cost, security levels, possibilities for acceleration, use of system charges and network loss factors.**
- **EDBs should develop and publish clear processes for: how they will handle connection requests in a timely fashion; opportunities for electrified process heat users to contract for lower security; and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).**
- **EDBs should share sufficient information about network demand to help process heat users determine whether they can limit the extent to which they increase peak demand on the network, and the nature of network security standards.**

- **EDBs should investigate how they could equitably pass on, to electrifying process heat users, the benefit of the eight-year delay in experiencing the full residual cost component of the TPM associated with an increased demand.**
- **Transpower should expand their renewable energy hub concept beyond the supply-side to the demand-side.**
- **Retailers, EDBs and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.**
- **EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.**
- **EECA should expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**
- **Ministries (such as Ministry for the Environment) need to work with reputable organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.**
- **Process heat users should enquire about government co-funding where the economics of decarbonisation are challenging. Where they are economic, EECA encourages organisations to explore the potential for self-funded acceleration.**

12 Appendix A: Worked Transmission Pricing Methodology (TPM) example

Below we use a practical example based on a stylised process heat user. While the example is based on the process heat user, the results should be treated as indicative only for the purpose of illustrating the transmission charges.

The process heat user has an existing demand connected to the EDB, who in turn connects the process heat user to the grid at one of Transpower's grid exit points (GXPs). For the avoidance of doubt, we are only looking at the transmission charges that would be applicable to the process heat user under the new TPM, not the distribution charges. Note also that there may be some averaging of charges that means that the EDB does not pass on the charges as outlined here.

The process heat user is also investigating replacing its coal boiler with an electrode boiler, which will substantially increase both its peak demand and total energy consumption.

We are only going to evaluate the three main components of the transmission charges, connection charges (CC), benefit-based charges (BBC), and residual charges (RC). As we discuss above there are a number of smaller adjustments that might also apply to ensure that Transpower's costs are recovered, and we cannot anticipate all of these. The one that we would have had to adjust for, the transitional price cap, is inflation adjusted, but with very high inflation the cap now barely applies.

We look at each charge individually for the starting point of how the new charges would apply to the process heat user's current load and then how those charges would change for the electrode boiler investment. We also estimate future charges for both scenarios. The initial prices are based on Transpower's Excel spreadsheet 'TPM indicative pricing model August 2022'.

12.1.1 Connection charges

The GXP is a grid node, not a connection node, and there is no Transpower spur line to the EDB. However, there is equipment at the GXP substation that is only there to connect the EDB to the grid. In addition to circuit breakers and other switchgear this includes two 220/33kV transformers as the GXP grid bus is 220,000 volts while the EDB takes supply at 33,000 volts. The annualised cost of these connection assets is assessed as $457k for the 2023/2024 pricing year. As the EDB is the only customer at the GXP these connection costs are all allocated to the EDB.

Where there are multiple customers on one connection then connection charges are allocated to customers on the basis of their Any time Maximum Demand (AMD) to the total of all customer's AMDs. This is a way in which the EDB could allocate connection charges to their customers that is consistent with the TPM. We can't know what the total of all AMDs within the EDB's network is (behind the GXP), so we will simply assume that the AMD of the combined network is the total of all AMD[151]. This gives a worse case allocation for the process heat user. AMD is the average of the 12 highest half-hour peaks in the given year or other time period. We have assessed the AMD for the process heat user based on data provided to us, which gives 18.1MW. We assume that the process heat user peak demand will remain constant unless they physically invest in new plant. For the GXP demand we use the peak demand forecast from Transpower's 'Transmission Planning Report 2021'.

This gives a forecast of connection charges for the process heat user's current demand in Table 20.

Table 20 – Forecast CC for the process heat user current demand

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
EDB AMD	110	113	115	118	120	122	125	127	129
Process heat user AMD	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user CC	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M

To assess the increase in charges for the addition of the electrode boiler we add 24MW to the process heat user's current AMD and to the EDB AMD but make no other alterations. Again, this is the worst case for the process heat user and gives the connection charges forecast in Table 21.

Table 21 - Forecast CC for the process heat user demand and new boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
EDB AMD	134	137	139	142	144	146	149	151	153
Process heat user AMD	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1
Allocation	31.4%	30.7%	30.3%	29.7%	29.2%	28.8%	28.3%	27.9%	27.5%
Process heat user CC	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M

[151] The network's AMD can be different to the sum of customers AMD as customer's AMD can occur at different times.

12.1.2 Benefit based charges

The Benefit Based Investments (BBIs) that are allocated to the EDB at the GXP are all Appendix A BBIs. This means that they are the pre-2019 investments chosen and assessed by the Authority for the guidelines given to Transpower. As the Authority had already determined these allocations, Transpower was instructed to use these allocations, which are attached in the TPM as Appendix A.

The investments and allocations that apply for the GXP are given in Table 22.

Table 22 – BBI projects and allocations for the GXP

BBI	Allocation
Bunnythrope Haywards	5.34%
HVDC	1.38%
LSI Reliability	10.57%
LSI Renewables	6.33%
NIGU	0.38%
UNIDRS	0.38%
Wairakei Ring	0.35%

Once these allocations have been made to the recovery costs of the above projects then the BBC charges that apply to the EDB for the GXP for the 2023/2024 pricing year are $1.07M.

When it comes to allocating the process heat user a share of these charges, the EDB could consider three methods that are consistent with the TPM. These methods are:

- Attempt to recreate the Authority's original method for allocation
- Attempt to apply the standard method from the TPM
- Apply the simple method from the TPM

It would not be feasible for a distributor to use the first two methods. They don't have the input information or models to replicate the results. The simple method models the beneficiaries by regions of the transmission network and then allocates these benefits to connection locations using Intra-Regional Allocators (IRA). The calculation method for IRAs is the most practical method, consistent with the TPM, for allocating BBIs.

There is a further complication, though. Different IRA calculations apply according to the nature of the investments. We think it unlikely that a distributor's methodology would be considered inconsistent with the TPM by simply picking one of the methods to apply to the total BBC. Both methods use the same calculation period – three years of data lagged by two years – that is, n-4 to n-2 inclusive; in this case 2018 to 2021. The allocation would then be based either on peak coincident demand over that period or total consumption over that period. The process heat user has a very low-capacity factor for an industrial user at 32%. This means that the two approaches yield very different allocations. Using peak coincident demand (using our assumptions from above) would give 16.5% and using consumption would give 3.6%. Given the peaking requirements for the process heat user and that most of the Appendix A BBIs could be described as investments to meet peak demand, we think that the EDB might use 16.5%. This would give the process heat user a starting BBC allocation of $175k (i.e. prior to the 25MW increase from the new electrode boiler).

As Appendix A BBIs are fixed allocations, the EDB is likely to treat the starting allocation for the process heat user as a fixed allocation. This gives the outcome in Table 23.

Table 23 - Worst case BBC allocation to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user CC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M

Appendix A BBIs are fixed allocations but do change for adjustments made for new customers, exiting customers, and substantial changes in consumption. We can't possibly predict what these changes might be and so we assume that these charges apply for the foreseeable future. The adjustments made for the new electrode boiler at the process heat user will help illustrate what could happen.

The GXP's BBC will also change if they are allocated charges for new BBIs. Again, we will not attempt to predict what these are and how they would be allocated but we will illustrate the potential impact of an imaginary investment on the charges for illustrative purposes.

The definitions for the events that cause an adjustment under the BBC are confusing. On consulting the Authority's original decision paper on the intent of the adjustments we believe that the proposed electrode boiler would be considered a 'Benefit-based Charge Adjustment Event: Large Plant Connected or Disconnected'. This event requires the large plant connection to be treated as if it's a new customer at the connection location but with the BBI allocation added to the relevant transmission customer, i.e. the EDB. Then all customers' allocations must be reduced by a factor to keep the adjustment revenue neutral. The adjustment formulae for calculating the adjustment seems to have a logic error, in that the same term used for the adjustment factor solution is used as an input to a formula, where the solution is used as an input to the adjustment formula – that is, prima facie a circular reference.

The formulae gross up the BBC at the connecting location based on the historical consumption (as assessed by Transpower) over 2014-2017 inclusive - the same period as residual charges. As the new electrode boiler is going to increase the consumption at the GXP by 138 GWh and the 2014-2017 average consumption is 452 GWh, then the gross increase in charges at the GXP will be 30.5%, which is $325k for the 2023/2024 pricing year. All customers who pay for the BBIs relevant to the GXP get a slight reduction in charges to ensure revenue neutrality. However, as the change in charges is $325k in a set of projects with annual cost of $211M then the adjustment is negligible.

It is worth noting that, if the BBC for the GXP had included post-2019 BBIs, the calculation of the increase in charges would have been more complicated. Although, it is also worth noting that the significant drivers on the BBC are two of the Appendix A BBIs, the HVDC ($116M of BBC) and NIGU (the new Pakuranga to Whakamaru 400/220kV line – $68M).

Once the EDB's charge have been adjusted for the new electrode boiler then this becomes a new fixed allocation of charges. If the new boiler's consumption proves to be more than 25% higher, then it might trigger a 'Benefit-based Charge Adjustment Event: Substantial Sustained Increase' event. There is no commensurate sustained decrease provision.

As the increase in the EDB's charges is attributable to the process heat user if the electrode boiler goes ahead then the resulting charges are shown in Table 24.

Table 24 - BBC for the process heat user with electrode boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Process heat user BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
+ boilers	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M
Total	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M

We have seen above that the addition of other new connections, unless very large or there are a large number, can make little difference to BBC.

To illustrate how new BBIs might affect the process heat user's charges we take the example of a potential upgrade of the HVDC (say a fourth cable across the Cook Strait). If this project were to cost $80M, which gives a very approximate $5M in additional costs per annum, and the benefits flowed through as per the Appendix A HVDC allocations, then the process heat user would attract a further $25K per annum in BBC.

12.1.3 Residual charges

Residual charges are the largest charges that are passed through. They are passed through initially as lagged peak charges and then adjusted based on lagged consumption. The RC assessed for the EDB for the 2023/2024 pricing year are $4.6M.

The AMD that is applied for AMDRbaseline is different to the one that applies for CC. However, we will assume the same allocation factor for AMD applies for the AMDRbaseline, i.e. that the process heat user will get 16.5% of the RC. If we assume there is no significant difference in total EDB consumption, then there will be no significant difference in the allocation of RC to the process heat user. In practice, this will depend on many factors including changes in consumption within the GXP network and elsewhere. This gives RC for the process heat user as shown in Table 25.

Table 25 - RC for the process heat user without boiler

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M

If the boiler is added there will be no immediate impact on the EDB's RC due to the adjustment factor being based on lagged consumption. After four years then consumption is based on four years of average consumption lagged by four years. Assuming that the new electrode boiler adds 138GWh per year starting in the 2023/2024 pricing year, then the adjustment in charges is shown in Table 26.

Table 26 - RC for the process heat user with boiler

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Adjustment factor	1.00	1.00	1.00	1.00	1.00	1.08	1.16	1.24	1.32
EDB charges	$4.60M	$4.60M	$4.60M	$4.60M	$4.60M	$4.97M	$5.35M	$5.72M	$6.09M
Increase for boiler	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.37M	$0.75M	$1.12M	$1.49M
Process heat user with boiler	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.50M	$1.88M	$2.25M

The charges reach their fully adjusted value in 2031.

12.1.4 Summary of charges

Table 27 summarises the outputs of Table 20, Table 23, and Table 25 to give the forecast allocation of transmission charges to the process heat user without the proposed electrode boiler.

Table 27 - Forecast allocation of transmission charges to the process heat user

	2023	2024	2025	2026	2027	2028	2029	2030	2031
CC	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M
BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M
Total	**$1.02M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.00M**

Table 28 summarises the outputs of Table 21, Table 24, and Table 26 to give the forecast allocation of transmission charges to the process heat user with the proposed electrode boiler.

Table 28 - Forecast allocation of charges to the process heat user with boiler

	2023	2024	2025	2026	2027	2028	2029	2030	2031
CC	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M
BBC	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M
RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.5M	$1.88M	$2.25M
Total	**$1.40M**	**$1.40M**	**$1.40M**	**$1.40M**	**$1.39M**	**$1.76M**	**$2.13M**	**$2.51M**	**$2.88M**
Increase	**$0.39M**	**$0.40M**	**$0.40M**	**$0.40M**	**$0.39M**	**$0.76M**	**$1.13M**	**$1.51M**	**$1.89M**

Table 28 also shows the increase in transmission charges after the boiler is installed. The charges are fully increased by 2031 to $2.88M, a $1.89M increase from what would happen without the boiler (ceteris paribus). Calculating the present value of 10 years (at 8% discount rate) of increased transmission charges gives $5.53M.

13 Appendix B: TIMES Modelling of Mid-South Canterbury fuel switching decisions

13.1 Introduction

To model a cost-efficient pathway to decarbonisation, TIMES-Mid-South Canterbury was created. This is based upon the IEA ETSAP TCP TIMES energy model generator, a bottom-up modelling system used worldwide. TIMES uses a linear programming solver to minimise the total energy system cost over the entire modelled horizon (2018-2049).

The TIMES-Mid-South Canterbury model is a stand-alone model separate to EECA's TIMES-NZ model, which consists solely of process heat assets in the Mid-South Canterbury region and is based upon RETA data.

In basic terms, the model finds the cheapest way to meet the projected heat demand of each site over the modelled horizon, essentially by considering the trade-off between continuing to run existing fossil fuelled assets and paying rising NZ ETS prices, compared to the cost of undertaking fuel switching to a low carbon heat source (biomass or electricity). The key output from the model is that it tells us the most optimal fuel choice for each site, and in what year it becomes economic for the site to undertake fuel switching.

13.2 Model inputs

13.2.1 Current state

Existing installed boiler capacity and fuel consumption by site is obtained from the demand assessment workstream. We apply an assumed boiler efficiency to fuel consumption values to obtain site process heat demand. This then forms the basis of a projection of process heat demand by site for the entire model period.

13.2.2 Fossil fuel prices

We take price forecasts for fossil fuels, that is, coal, diesel, and LPG, from RETA analysis.

13.2.3 Carbon price

The price applied to CO_2 emissions is the primary driver of decarbonisation in the model. We use a modified version of the CCC's demonstration pathway, which accounts for the difference between the CCC's pathway and the actual carbon price over the past year or so.

13.2.4 Demand reduction, heat pump, and fuel switching projects

Confirmed demand reduction, heat pump, and fuel switching projects have been implemented as scheduled.

Unconfirmed demand reduction and heat pump projects are implemented in 2023 and 2024 respectively. This reflects the fact that these projects are generally economically favourable and hence sites will implement them ASAP. We assume that unconfirmed fuel switching projects will not take place until any DR and HP projects are complete, hence 2025 is the earliest that sites can undertake a fuel switching project.

The capital costs for fuel switching projects are provided by the demand assessment workstream (which uses ETA data where known, and default values based on required capacity where unknown).

For electrification projects, if an electrical supply upgrade is required, the project capital cost includes the portion of the upgrade cost that the site must pay. For example, if a MW electrode boiler requires a $5M supply upgrade at either the distribution or transmission level, $2.5M will be added to the capital cost of the electrode boiler.

We also apply annual network charges (on a per MW basis) to electrification projects. With the exception of this network charge, operation and maintenance costs are not included for either biomass or electrification projects as these are minor compared to fuel and NZ ETS costs.

The model uses a discount rate of 7%.

13.2.5 Additional constraints and special cases

All sites which use coal must transition by 2037 at the latest to align with the Government's intention that coal for low and medium temperature process heat be phased out by that year.

Facilities covered by the carbon neutral government programme, such as public schools and hospitals, must transition to a low carbon heat source by 2025.

13.2.6 Low carbon energy sources

13.2.6.1 Electricity

There is no constraint on the availability of electricity in the model – it is assumed that there is sufficient supply to meet demand (or that supply upgrades can meet demand) if a site is willing to pay for it.

We apply a special 5c/kWh flat rate for the first 10 years from when fuel switching projects become available (i.e. from 2025 to 2034 inclusive). This reflects special offers from retailers to encourage process heat electrification. From 2035 onwards, we use EnergyLink's monthly electricity price forecast.

Site-specific load curves are applied where known, otherwise default load curves based on sector are used. This allows the model to factor in the seasonality of electricity prices as well as seasonal variability in site demand.

A flat emission factor of 50 tCO2-e/GWh is assumed to represent the future average emissions intensity of NZ grid electricity.

13.2.6.2 Biomass

We use data from the biomass availability and cost workstreams to generate biomass price and supply inputs for the model. Biomass supply is split into tranches of differing quantities and prices, based on the upstream source of the biomass. For instance, the model has access to approximately 140TJ annually from processor residues at a price of $16.76/GJ, compared to 440TJ annually from wilding conifers at a price of $33.17/GJ. The total quantity of biomass available is limited to approximately 1680TJ from now until 2035, with a smooth increase to 2270TJ in 2040. This is to reflect an expected increase in harvesting post-2037 as planted forests reach maturity.

As the model increases its use of biomass, it will exhaust the cheaper tranches of supply and thus need to start using more expensive inputs. This allows for greater granularity than providing a simple average cost based upon expected demand.

There is no emission factor applied to biomass.

13.3 Results

By aggregating the model's fuel choice and transition year for each site, we obtain a suggested optimal pathway for the region to follow. This pathway can be seen in the graphs below.

Further explanation is as follows:

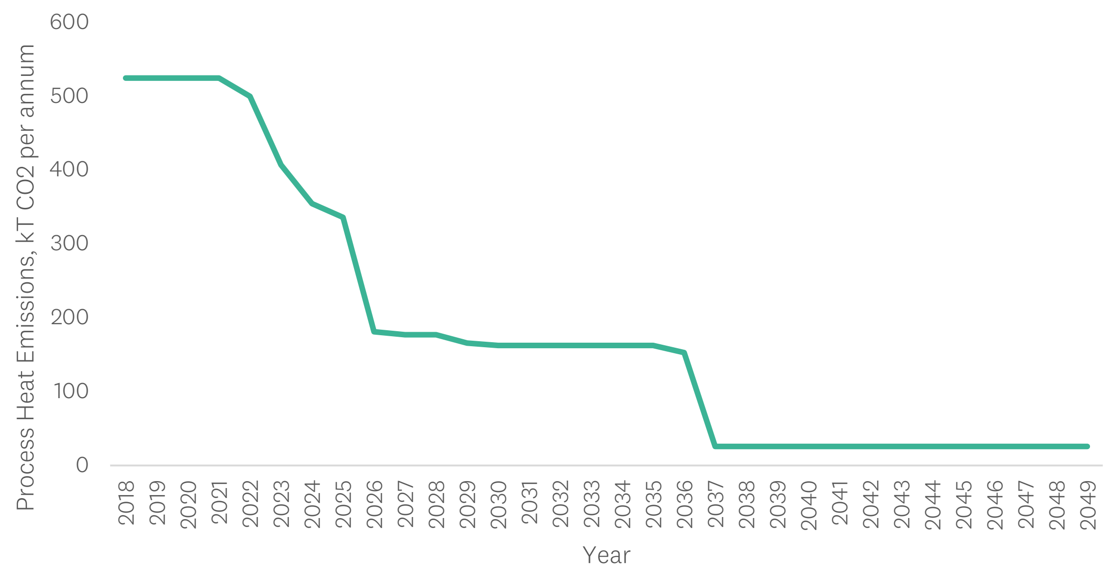
- Where heat pumps are an option for fuel switching (i.e. in sites which only require low temperature heat as opposed to steam), these are preferred thanks to their high thermal efficiency.
- For sites with LPG or diesel, the model chooses to fuel switch right away in 2025 as the relatively high prices and carbon intensity of these fuels make low carbon options more economic.
- For sites with coal, whether it is economic to undertake fuel switching prior to the 2037 deadline depends on several factors:
  - Boiler utilisation – the lower the utilisation rate of the boiler, the less likely it will be economic to fuel switch (running cost savings are relatively less significant compared to the upfront CAPEX required).
  - Project capital costs:
    - There are numerous factors which could influence this, for instance, some sites might have an existing coal boiler and fuel handling system that can be relatively easily converted to run on biomass, and this may be significantly cheaper on a per MW basis compared to other sites which would need a brand-new boiler and fuel handling system.
    - Another factor influencing CPAEX is the level of complexity/cost of any electrical supply upgrades required for electrification projects.
  - Ongoing running costs.

For sites which don't fuel switch until 2037, most go to biomass, essentially exhausting the biomass supply. This is interesting because the average unit price of electricity from this year onwards is similar to, or slightly less than the unit price of biomass in the more expensive biomass tranches that the model decides to use (e.g. $30-40/GJ for electricity vs $36.50 for biomass from Export KI logs). This suggests that small changes in assumptions made around costs, fuel availability, NZ ETS prices, and perhaps even the assumed emissions factor for grid electricity (50 tCO_2e / GWh) could easily swing the balance from one fuel to the other.

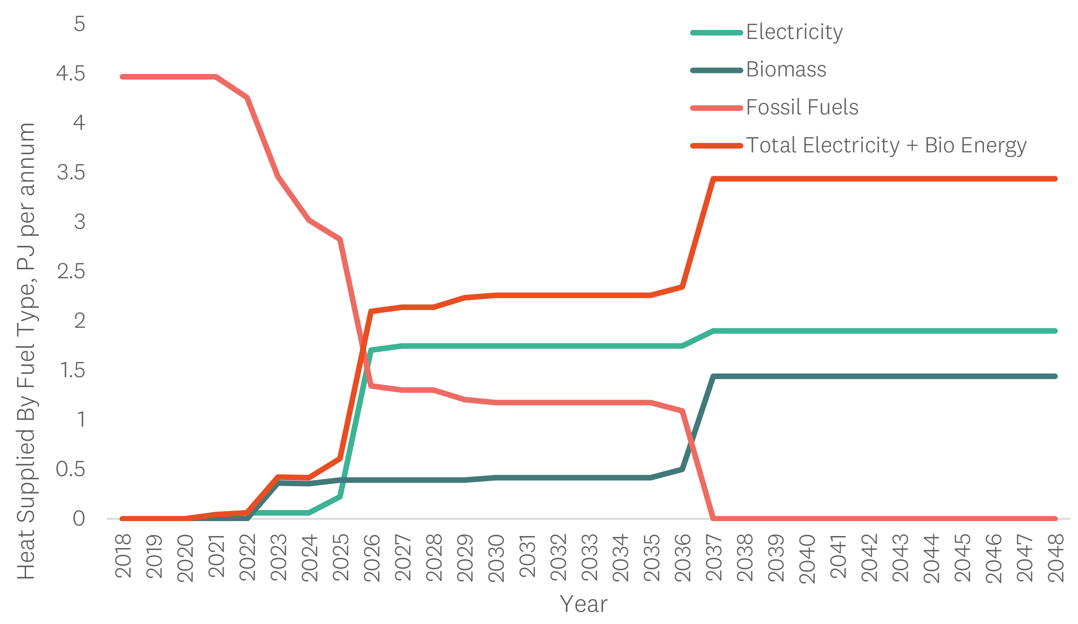
Note that, in general, dairy processing favours electrification due to winter being the off season for these sites, meaning they are less exposed to the higher electricity prices that we get during winter. The opposite is true for meat processing, which generally has peak demand in winter and lower demand in summer.

It should also be emphasised that for sites which do not fuel switch prior to 2037, lack of low carbon fuel availability is not the cause.The model does not pick up any of the more expensive (>$30/GJ) biomass tranches available prior to 2036 (i.e. low grade export logs or wilding conifers), while there is no limit at all on electricity supply, with the 5c/kWh electricity price available from 2025 to 2034. If even this price is not sufficient to make fuel switching economic, sites will either need other reasons to do so, or will require assistance to overcome the financial hurdle.

Emissions Reduction Timeline



Heat supplied by fuel type, for fuel switching projects



14 Index of figures

Index of figures

June 2023

Government Leadership

Regional Energy Transition Accelerator (RETA)

Mid-South Canterbury
Phase One Report

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY