Government Leadership

South Island Regional Energy Transition Accelerator RETA

Phase One Report

July 2024

EECA
TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

He kupu takamua – Te Waipounamu

E tutuki ai te whāomoomo ā-pūngao me te whakawhiti kora kaitā, me whai pārongo whai mana i te taha o te mahi ngātahi pakari ā-rohe.

I tēnei wā, e ono ngā pūrongo kua tukua e tā EECA hōtaka wawata, e Regional Energy transition Accelerator (RETA) e whakakapi ana i Te Waipounamu whānui. Koinei te whakakapinga o te tūāoma mahi tuatahi i ngā rohe o te taitonga.

E whakakao ana tēnei pūrongo i te popono ngao wera i matapaetia, i whakamaheretia i te pito waenga ki te kaitā, waihoki ngā whakaratonga pūngao whakahou hei tautoko i te whakahohorotanga o ngā kaupapa whakaheke waro puta noa i Te Waipounamu.

Ko te wera o te whakanao me te tukatuka rawa mātāmua te 25% o ngā puhanga ngao o te motu, nā reira ka nui te pānga o te whakaheke i te whirinakitanga ki ngā kora mātātoka.

E tuku ana te pūrongo i ngā pārongo whānui mā ngā pakihi e whakaaro ana kia tukatuka i te whakahekenga waro ā-wera i ngā tau kei mua. Kua āwhina tēnei i ngā kaiwhakatau i te wāhi ki ngā haumitanga rawa, tūāhanga anō hoki. Nā konei i heke ai ngā utu, me te aha, ka hua ake ko te whakatinanatanga me ngā mahi nā runga i te tātaritanga.

Nā ēnei mahi i kitea ai te whai hua a ngā wāhanga pēnei i te whakarato kora me te tūāhanga i te aronga ngātahitanga. Ka whirinaki ki ngā akoranga nō ngā mahi whāomotanga pūngao me te whakaheke waro e motuhake ana ki ētahi wāhi, kua mahia kētia e ngā pakihi, ā, ka tukua he pūrongo e pā ana ki te takatūtanga o ngā pūnaha whakarato ā-rohe.

E whakahīhī ana a EECA i tāna mahi tahi ki ngā umanga whakawhanake ōhanga, me ētahi atu nō te taha popono me te whakarato – e tino hāngai ana tērā ki a Transpower, ki a EDBs, ki ngā kaiwhakarato papatipu koiora tiputata me ngā kaiwhakahaere ngahere, otirā ngā kaiwhakamahi pūngao ahumahi waenga ki te kaitā.

E manawareka ana i te hunga i taea ai ēnei mahi nā rātou, me tō rātou tuwhera ki ā mātou kaitātari, kaiwhakatauira anō hoki – i tino whai hua ngā kitenga me ngā tūtohutanga i te pērā. Kua whāngaihia e tō mātou tīma RETA ō rātou mātangatanga, me tō rātou hiamo, manawa piharau anō hoki i hua ake ai ko tētahi mahi whānui. Waihoki, e manako ana ka tino wāriutia te mahi nei.

Ahakoa e kitea ana te pikinga o te ānga, he mahi anō kei mua i te aroaro. Me ū tātou kia mahi tonu, kia tere ake anō hoki e pai ai tā ngā pakihi me ngā rohe puta noa i Aotearoa whakawhiti ki tētahi ōhanga tukuwaro iti me te nanao atu ki ngā ara ka pihi ake i runga i te pūngao mā me ngā hangarau atamai.

E whakatauira ana te RETA i te wāriu o te tuku i ngā pārongo pai katoa, o te whai i te tirohanga ā-pūnaha, me te mahi tahi puta noa i tētahi pūnaha hauropi pūngao tiputata. Mā te takahi i ngā raru ā-rohe ki ngā urupare ā-rohe e pai ake ai te ripanga whai hua ā-utu mō te katoa i tēnei wero.

E hiamo ana mātou ki te koke ki te tūāoma whakatinanatanga i a tātou ka takahi tonu i tēnei ara.

1 Foreword

Achieving energy efficiency and fuel switching at scale requires authoritative information alongside strong regional collaboration.

EECA's ambitious Regional Energy Transition Accelerator (RETA) programme has so far delivered six reports covering the entire South Island, wrapping up phase one of activity in the southern regions.

This report combines the forecasted and mapped stationary heat energy demand at the medium to large end, as well as renewable energy supply to support the acceleration of decarbonisation projects across South Island.

Heat used in manufacturing and in the processing of primary products currently makes up around 25% of our country's energy-related emissions, so reducing reliance on fossil fuels will have a big impact.

The report provides comprehensive information for businesses considering process heat decarbonisation in the years ahead. This has helped decision makers with asset and infrastructure investments, reducing costs and resulting in implementation and action because of the analysis.

This work has made it clear that areas like fuel supply and infrastructure would benefit from being tackled collectively. It leverages lessons from site-specific energy efficiency and decarbonisation work that has already been carried out by businesses and provides information on the readiness of regional supply-side systems.

EECA is proud to have worked collaboratively with economic development agencies, and others from across the demand and supply side – in particular Transpower, EDBs, local biomass suppliers and forest owners, and medium to large industrial energy users.

We are grateful for everyone who has made this work possible, and their openness with our analysts and modelers – the findings and recommendations are much richer for it. Our RETA team have provided not only expertise, but enthusiasm and commitment that has led to a comprehensive, and we hope extremely valuable, piece of work.

While we see momentum building, there is more to do. We must commit to doing more, faster, to enable businesses and regions across New Zealand to transition to a low emissions economy and take advantage of the opportunities that emerge with clean energy and clever technologies.

The RETA demonstrates the value of providing the best possible information, taking a systems level perspective, and coordinating across a local energy ecosystem. Tackling regional problems with regional solutions will improve the cost-benefit equation for all involved in this challenge.

We now look forward to moving into the implementation phase as we all continue along the journey.

Dr Marcos Pelenur
Chief Executive, EECA

2 Table of contents

EECA's ambitious Regional Energy Transition Accelerator (RETA) programme has so far delivered six reports covering the entire South Island, wrapping up phase one of activity in the southern regions.

3 Executive summary

Over the past two years

EECA has delivered

6

Six Regional Energy Transition Accelerator (RETA) reports, covering Nelson Marlborough Tasman, North Canterbury, Mid-South Canterbury, West Coast, Otago, and Southland.

12

12 workshops and numerous site visits and discussions with regional stakeholders in the South Island.

These reports have analysed

273

273 process heat sites in the dairy, meat, industrial, and commercial sectors.

600

Nearly 600 individual decarbonisation projects, which were assessed for their potential to reduce fossil fuel use and emissions.

Resulting in an unprecedented level of regional decarbonisation analysis.

The completion of these RETA regional reports now allows us to obtain a new and comprehensive picture of the entire South Island, from a process heat decarbonisation perspective.

80%

South Island process heat sites account for nearly 80% of New Zealand's coal consumption[1], and 11% of LPG consumption. The emissions from these sites make up around 28% of New Zealand's total process heat emissions and over 5% of total energy emissions.

15 years

Nearly 1Mt CO_2e per annum of process heat emissions reductions could be economic within the next 15 years.

32%↓

Energy efficiency could reduce the use of fossil fuels by 32%—39% in the South Island RETA.

6.2Mt

Commercial decision-making based on MAC values (the 'MAC optimal' pathway) could accelerate emissions reductions, reducing cumulative long-lived emissions by 6.2Mt between now and 2037 compared to a 'business as usual' pathway.

25%↓

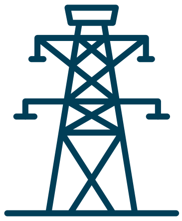
Completed or confirmed fuel-switching projects will deliver a 29% reduction in process heat emissions compared to 2022. Demand reduction and thermal efficiency projects could further reduce emissions by 25%.

1 For the purposes of producing energy directly for a consumer. This excludes the use of coal for electricity generation. If the total consumption of coal in New Zealand is considered (~43PJ), then the SI RETA accounts for 40% of this figure.

Our MAC Optimal pathway allows us to quantify the implications for the island's electricity and biomass markets:

$3B

The pathway would increase South Island electricity consumption by 2,041GWh in 2037, requiring up to $3B investment in renewable generation, peaking generation or storage, and transmission and distribution infrastructure.



Two-thirds of the $200M of transmission and distribution investment required for the MAC Optimal pathway will require lead times of between 2-4 years to design and construct these connections (including sourcing the equipment), not allowing for regulatory consultation and approval processes, or obtaining the consents and property rights to enable the works. Our analysis did not consider the extra time required, but it appears that network investment may be a limiting factor for a number of the electrification decisions desired by process heat users.

20%

While we have not evaluated flexibility in each process heat user's demand (due to insufficient information about each user's underlying process), if 20% of South Island process heat users' peak demand (in the MAC Optimal pathway) was flexible and able to respond to market or network signals, it would provide a service to the electricity system that is equivalent to a 100MW grid-scale battery. This could also reduce the costs of electricity connection and procurement for these process heat users by up to $100,000 per MW per year.

$600M

The MAC Optimal pathway would create new demand for nearly 5.7M tonnes of woody biomass over the next 13 years, worth between $525M to $604M over that period.

Annually the South Island's use of woody biomass for bioenergy would more than double, fully consuming available and currently unutilised processor and harvesting residues and minor species.

Arthur's Pass, Canterbury, New Zealand.

Arising from this analysis of South Island process heat, we make the following recommendations:

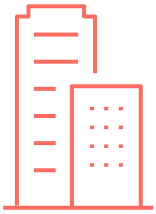
The Forestry Owners Association should develop an 'energy grade' to increase understanding of the costs of recovering harvesting residues, drive more efficiency into collection of residues and therefore assist in the development of bioenergy markets.

Economic development agencies and relevant businesses should explore opportunities to enhance wood pellet manufacturing near major biomass resources.

Economic development agencies and relevant businesses should explore the opportunity to establish local capability to assemble and/or manufacture heat-pump components.

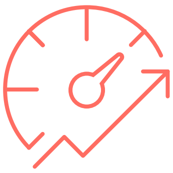
Electricity distribution businesses (EDBs) should provide standardised 'connection feasibility information templates' to improve the efficiency of information sharing with process heat users.

EDBs should make capital contributions and network pricing policies and methodologies easier to understand and easier for process heat users to estimate the financial impact on electrification business cases.



Retailers and flexibility aggregators should continue to develop products and services that make it easy for process heat users to discover, evaluate and enable flexibility where it can reduce their capital and operating costs of electrification.

EDBs should improve their network pricing signals for flexibility based on the value to the network.



Objective scenario-based carbon price forecasts need to be developed so that decarbonising organisations can incorporate them into their business cases. Ministries (such as Ministry for the Environment) need to facilitate appropriately qualified organisations to produce these.

EECA will expand the scope of future Regional Energy Transition Accelerators to include transport, in order for a more complete picture of a region's energy pathway. EECA should also make models available for stakeholders to use to explore pathways under different assumptions.

4 Background

Over the last two years, EECA has delivered six Regional Energy Transition Accelerator (RETA) reports and workshops, covering the entire South Island. Through this work, EECA has collaborated closely with process heat users, electricity industry participants, biomass providers, and economic development agencies[2].

RETA reports are focused on the use of fossil fuels for process heat usage – typically coal, diesel and gas (LPG in the South Island). While some low-emissions fuels are already used for process heat in the South Island, RETA reports are focused on significantly reducing emissions, through the reduction of fossil fuels.

Other types of energy consumption – particularly transport – will be a significant part of each region's transition away from fossil fuels. Process heat was chosen for this first version of RETA because EECA was able to obtain sufficiently granular and specific information on each process heat user to allow us to conduct individual assessments of their decarbonisation options. This was not possible for transport. EECA is committed to including transport in future regional energy analyses, so that the overall 'system' effects of energy transitions can be correctly identified.

Such comprehensive analysis and understanding of process heat energy use at the business level[3] in the context of the regional energy ecosystem has, to the best of our knowledge, never been conducted in New Zealand's history.

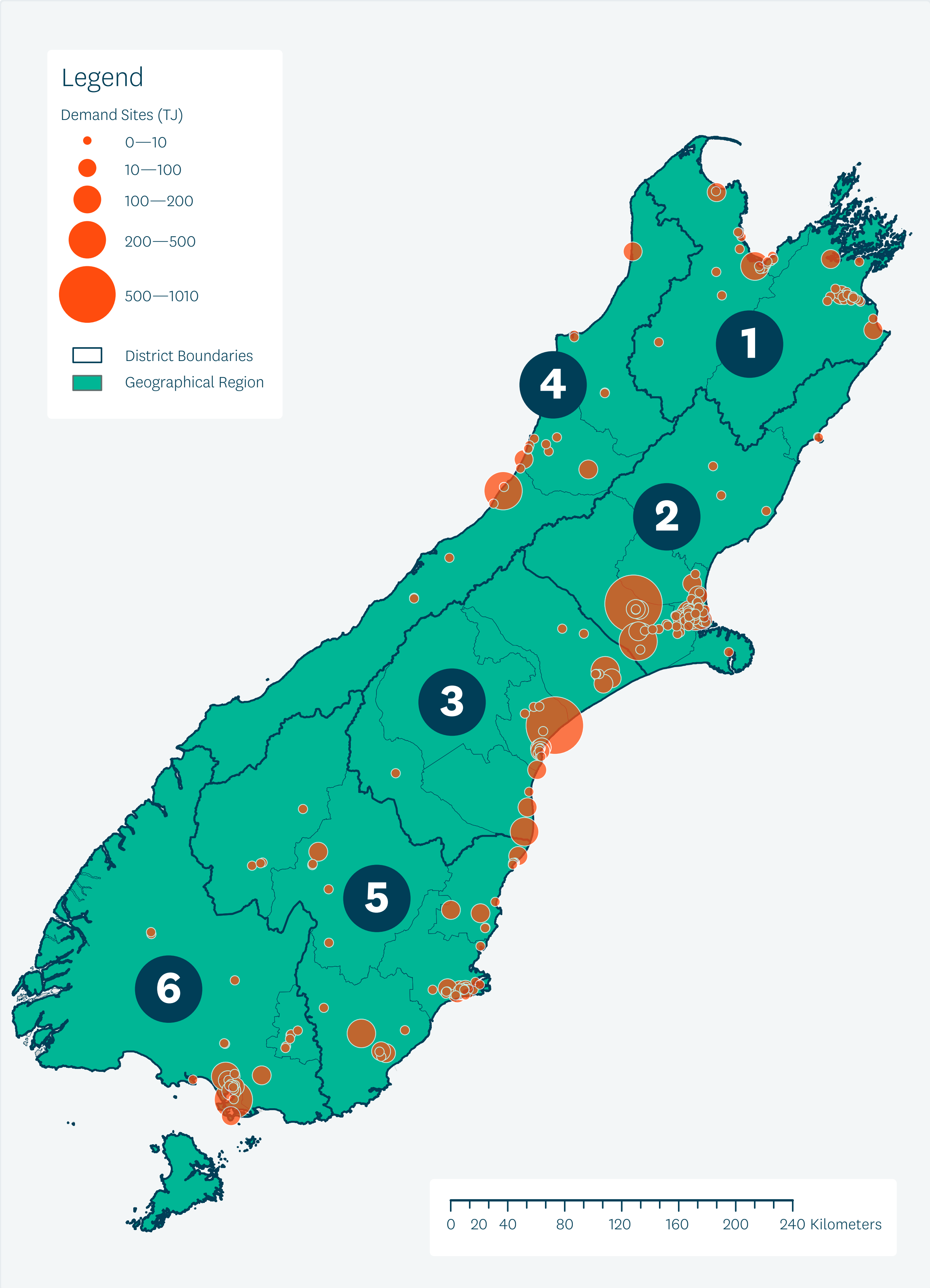
The six regions covered are shown in Figure 1:

1. **Nelson, Marlborough, Tasman**
2. **North Canterbury**
3. **Mid-South Canterbury**
4. **The West Coast**
5. **Otago**
6. **Southland**

[2] See Appendix for a summary of participants.

[3] The focus was on sites that had fossil fuelled boilers greater than 500kW in capacity, but the nature of the analysis meant that a number of sites (e.g. schools) that had boilers smaller than this were included.

Figure 1 – Map of area and demand sites covered by the South Island RETA



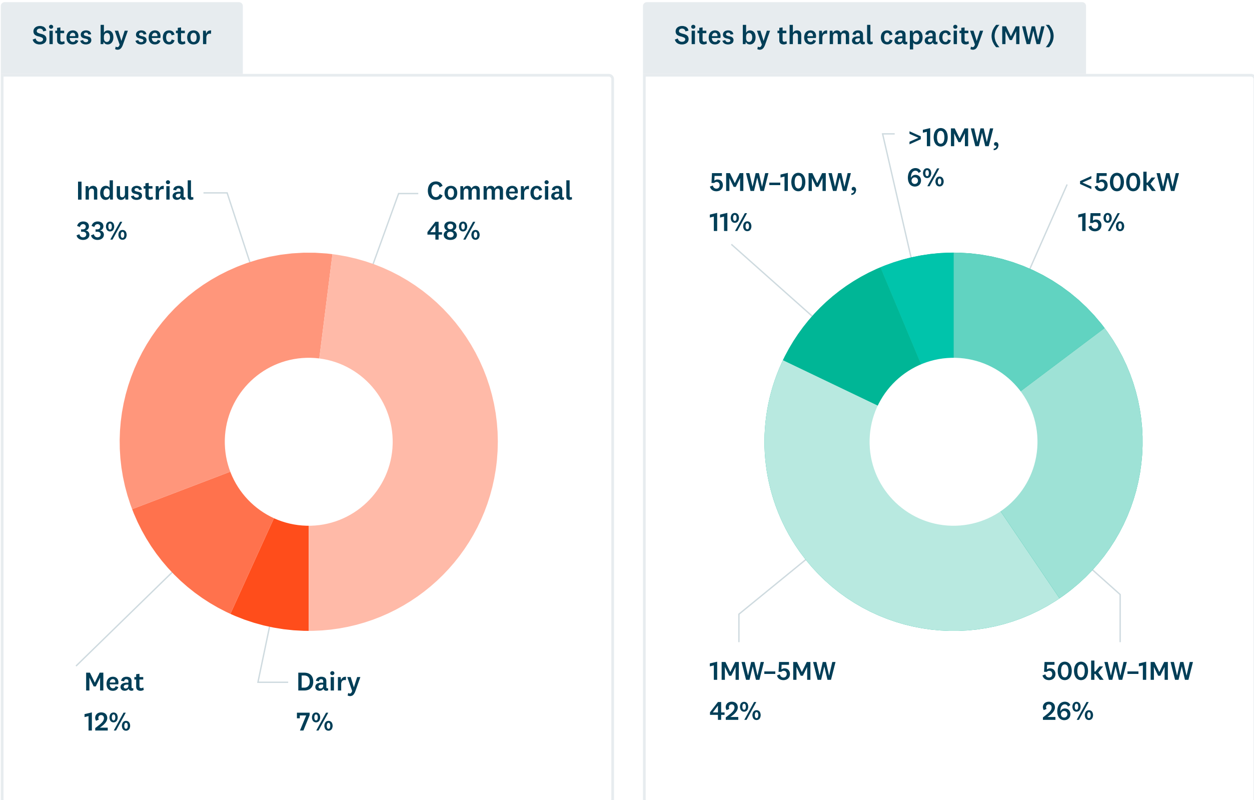
Each regional RETA involved detailed workstreams concentrating on supply-side resources and process heat requirements, comprehensive economic and pathway analysis, and two key workshops with active stakeholders[4]. These activities culminated in an integrated report that outlined the emissions savings, fuel and commercial implications of fuel switching from fossil fuels to biomass or electricity.

This combined South Island report synthesises the results of the individual RETAs to highlight what was achieved, the progress made since, and the new insights that come from having a comprehensive database covering the whole island.

4.1 The profile of South Island process heat sites

Across the South Island, the final RETA reports assessed 273 process heat sites. The process heat users came from the dairy, meat, industrial and commercial sectors[5], typically with process heat equipment with a capacity exceeding 500kW[6] (Figure 2).

Figure 2 - Characteristics of South Island RETA sites



[4] See Appendix for a summary of participants.

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

[6] As the RETA workstreams moved through the South Island regions, the analysis incorporated an increasing number of smaller process heat users (i.e lower the 500kW of thermal capacity), such as schools and swimming pools, where EECA has detailed information about their decarbonisation pathways.

4.2 How RETA supported process heat site assessments

The South Island RETA helped process heat organisations evaluate individual decarbonisation projects. These projects fell into three categories of emissions-reducing projects:

Demand reduction	Thermal efficiency	Fuel switching
163 projects evaluated	**144** projects evaluated	**286** projects evaluated
E.g. reducing heat demand through process optimisation	E.g. highly efficient heat pumps for hot water demands, or using heat recovery from refrigeration	Switching away from fossil fuel to a low-emissions fuel (e.g. biomass and/or electricity)

Across the 273 sites, nearly 600 individual projects were assessed for their potential to reduce fossil fuel use and emissions, as well as for commercial attractiveness.

Each regional RETA report made recommendations regarding how the transition from fossil fuels to low-emissions fuel could be accelerated to support New Zealand to meet its emissions reduction targets, while benefitting process heat users and low emissions fuel suppliers.

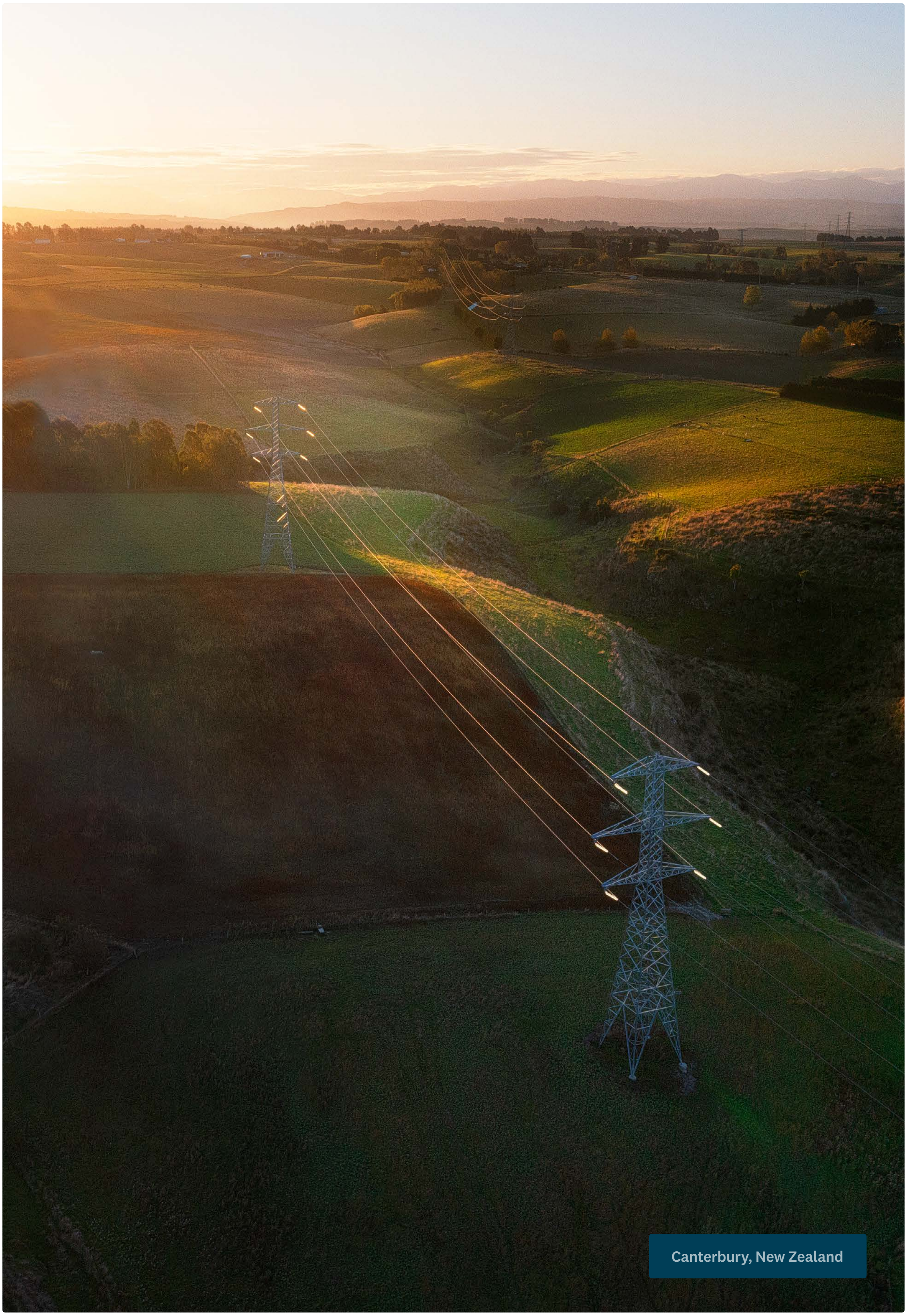
J.S Ewers, Nelson, New Zealand.

4.3 South Island RETA pathways

The analysis of around 600 decarbonisation projects allowed the RETA process to simulate a range of ‘pathways’, illustrating the pace of emissions reductions that could be achieved using different scenarios of decision making. Broadly, these pathways represented the following scenarios:

Pathway name	Description
Biomass Centric	All unconfirmed site fuel switching decisions proceed with biomass where possible, with the timing based on any publicly available information, or the phaseout of coal boilers required by the National Policy Statement (NPS) for greenhouse gas emissions from industrial process heat.
Electricity Centric	All unconfirmed fuel switching decisions proceed with electricity where possible, with the timing set as above.
BAU Combined	All unconfirmed fuel switching decisions (i.e. biomass, electricity or geothermal) are determined by the lowest MAC value for each project, with the timing based on the criteria in the fuel-centric pathways above.
MAC Optimal	Each site switches to a heat pump or switches its boiler to the fuel with the lowest MAC value for that site. Each project is timed to be commissioned the first year its optimal MAC value drops below a ten-year rolling average of the Climate Change Commission’s Demonstration Path of future carbon prices. If the MAC does not drop below the ten-year rolling average, then the timing based on the fuel-centric pathway criteria is used.

Further, as presented below, we tested the sensitivity of the MAC Optimal pathway to the assumed carbon price. This provided us with a rich picture of the potential acceleration in emissions reductions.



Canterbury, New Zealand

5 A new picture of South Island process heat emissions reduction potential

South Island process heat sites account for nearly 80% of New Zealand's direct consumption of coal for energy purposes.

The South Island RETA projects represent a material portion of New Zealand's process heat fossil fuel usage and emissions. The 18PJ per year of fossil fuels used for process heat on these sites accounts for 11% of LPG consumption and 80% of New Zealand's total coal consumption[7]. The 1.7Mt of emissions from these sites is around 28% of New Zealand's total process heat emissions[8], and over 5% of the country's total energy emissions.

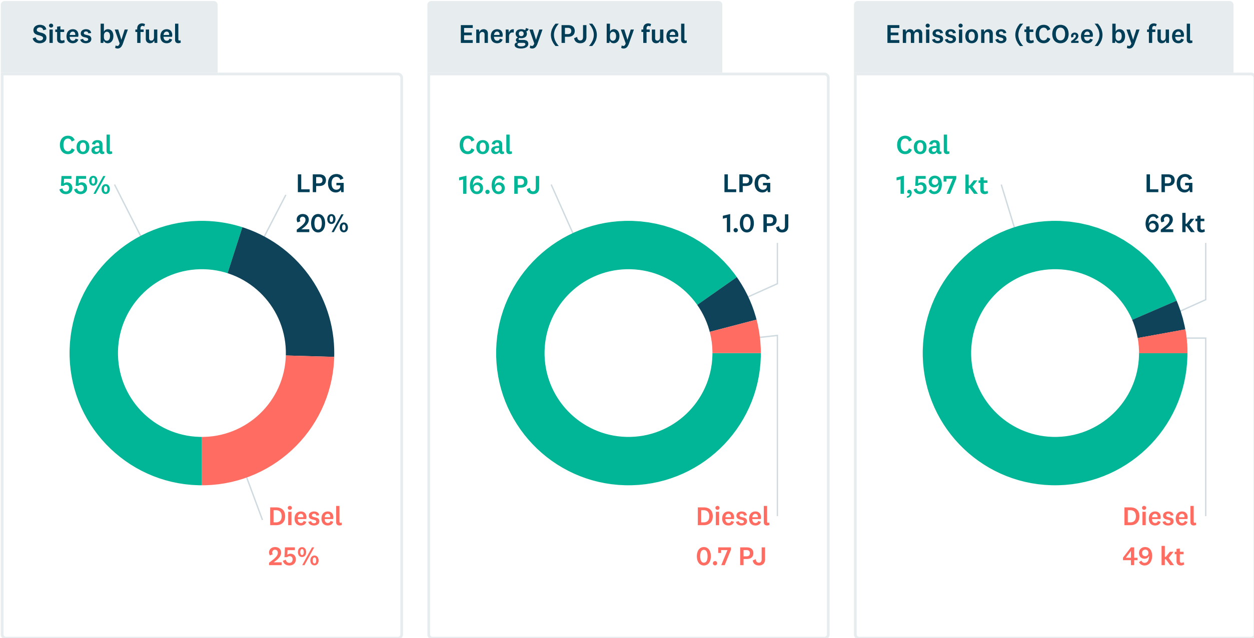
Most South Island process heat emissions are from coal. Coal accounts for 94% of the total emissions across these sites (Figure 3).

18PJ/y	1.7Mt/y	1.5GW
Fossil fuels consumed in 2022	**Scope 1 fossil fuel CO_2e emissions**	**Thermal capacity**

[7] The South Island process heat sites also account for 1% of New Zealand's total diesel consumption. In respect of coal, the figure provided above relates to South Island process heat consumption as a proportion of New Zealand's total coal consumption for the purposes of providing direct heat to an energy consumer. This excludes the use of coal for electricity generation. If the total consumption of coal in New Zealand for energy purposes is considered (~43PJ), then the SI RETA accounts for 40% of this figure.

[8] New Zealand's total gross emissions in 2022 were 78Mt CO_2e (https://www.stats.govt.nz/information-releases/greenhouse-gas-emissions-by-region-industry-and-household-year-ended-2022/). Process heat emissions are reported by MBIE to be approximately 8% of New Zealand's gross emissions (https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/decarbonising-process-heat/), i.e. New Zealand process heat emissions were approximately 6Mt in our baseline 2022 year.

Figure 3 – Process heat fossil fuel usage in the South Island – sites, energy, and emissions. Source: EECA

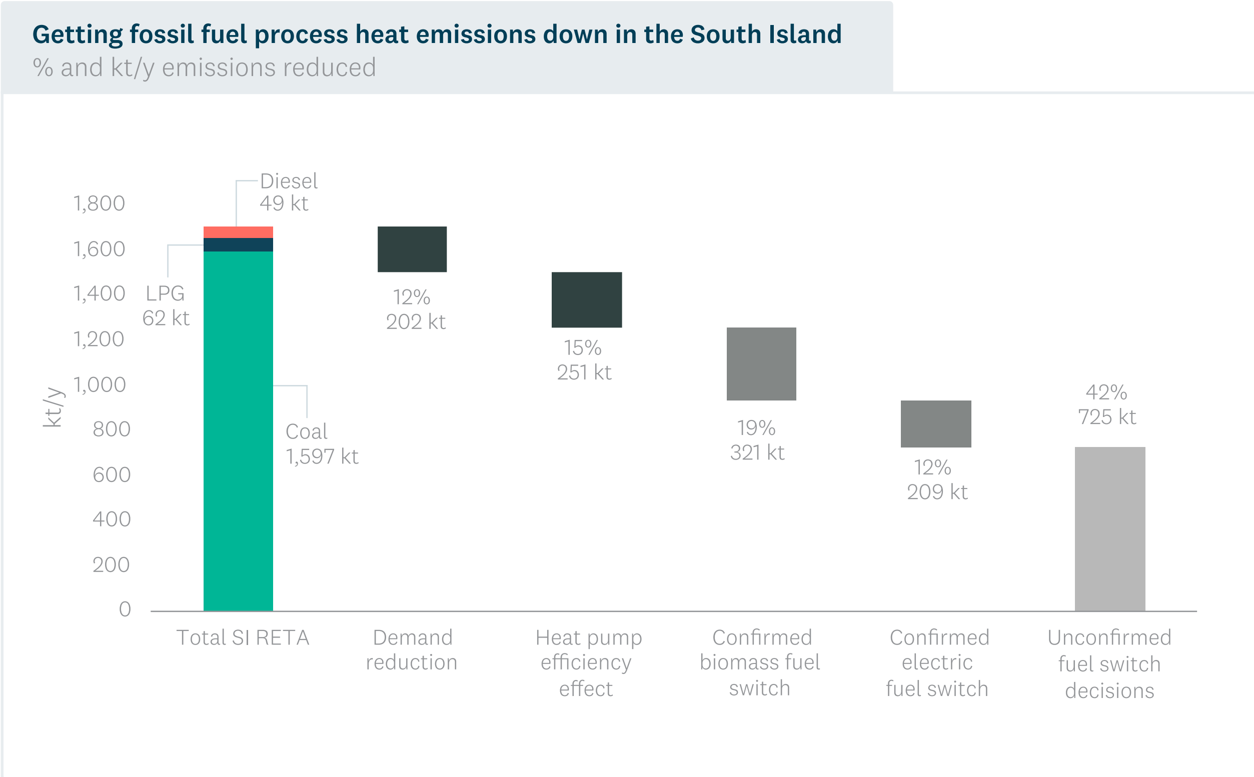


Kumara Hydro Station, West Coast, New Zealand.

5.1 The impact of decarbonisation projects on emissions

Figure 4 shows the potential impact of the three categories of decarbonisation projects outlined in Section 4.2 (demand reduction, thermal efficiency[9] and fuel switching) on South Island process heat fossil fuel emissions.

Figure 4 – Potential impact of demand reduction, thermal efficiency and fuel switching on South Island process heat fossil fuel emissions, 2022-2037. Source: EECA



Completed or confirmed fuel-switching projects will deliver a 29% reduction in South Island process heat emissions, compared to 2022.

At the time of writing this report, nearly 100 fuel switching projects have either been completed, or have been confirmed[10] by South Island process heat users (and will be completed within the next few years). Together, these completed or confirmed projects will deliver 530kt/year of process heat emissions reductions (shown by the grey colours in Figure 4), 31% of the baseline emissions in 2022. They will create 503GWh per year of new demand for electricity, and 460kt/year of new demand for biomass[11].

[9] In the regional RETA reports, this was usually referred to as 'heat pump efficiency'. We use the slightly broader 'thermal efficiency' term here, to include technologies such as Mechanical Vapour Recompression (MVR). However, the vast majority of thermal efficiencies modelled in RETA projects is through the use of heat pumps, with assumed efficiencies between 300%-350%.

[10] By 'confirmed' we mean that the organisation has finalised their fuel switching decision and allocated investment funding to the project. Any projects that have not reached this decision point are referred to as 'unconfirmed'.

[11] Unless specified otherwise, all weight-based figures in RETA reports are 'green tonnes', or 55% moisture content.

A number of these fuels switching projects received industrial co-funding from EECA.

One-third of these confirmed or completed emissions reductions were announced by process heat users while they were participating in the regional RETA process.

Demand reduction and thermal efficiency could deliver a further 25% reduction in emissions and reduce fuel switching CAPEX by $390-585M.

Many demand reduction and heat pump efficiency projects are unconfirmed but offer significant emissions reduction potential – 453kt of emissions reductions could be delivered through these projects. Compared to our 2022 baseline emissions from these sites of 1.7Mt/year, this represents 26% of 2022's process heat emissions in the South Island. Further, demand reduction and thermal efficiency projects also reduce the thermal capacity required from investment in fuel switching – reducing the size of boilers required, and potentially the size of network connections (for electrode boilers) and onsite biomass storage facilities (for biomass boilers). The reduction in boiler capacity alone could be 390MW – a reduction in capital cost of between $390M and $585M.

Port Blakely – Waimate, Canterbury, New Zealand

5.2 When could emissions reduction investments become economic?

Nearly 1Mt CO_2e of emissions reductions could be 'economic' within the next 13 years based on our commercial modelling – nearly 60% of the 2022 emissions from these sites.

Based on plausible estimates of cost, each of the ~600 project options were modelled to estimate their 'marginal abatement cost'[12], or MAC. The MAC value describes the cost to the organisation (net of any savings from no longer purchasing fossil fuels) of investing in a demand reduction, thermal efficiency or fuel switching project. The cost is expressed as a dollar amount per tonne of emissions reduction achieved ($/t CO_2e). This allows us to compare different emissions reduction options across all the ~600 projects.

Where multiple fuel switching options existed (e.g. biomass boiler, electrode boiler, and sometimes a heat pump[13]), the MAC values were used to determine which option was the lowest cost to the organisation. Demand reduction and thermal efficiency projects typically only had one option, but a MAC was still calculated to understand the relative economics of these projects.

Figure 5 summarises the optimal (i.e. lowest) MACs associated with each project[14], and the emissions reduced by these projects. Projects that have MAC values below the forward average shadow price of carbon from the Climate Change Commission's demonstration pathway are coloured in green; the remaining projects are coloured in red.

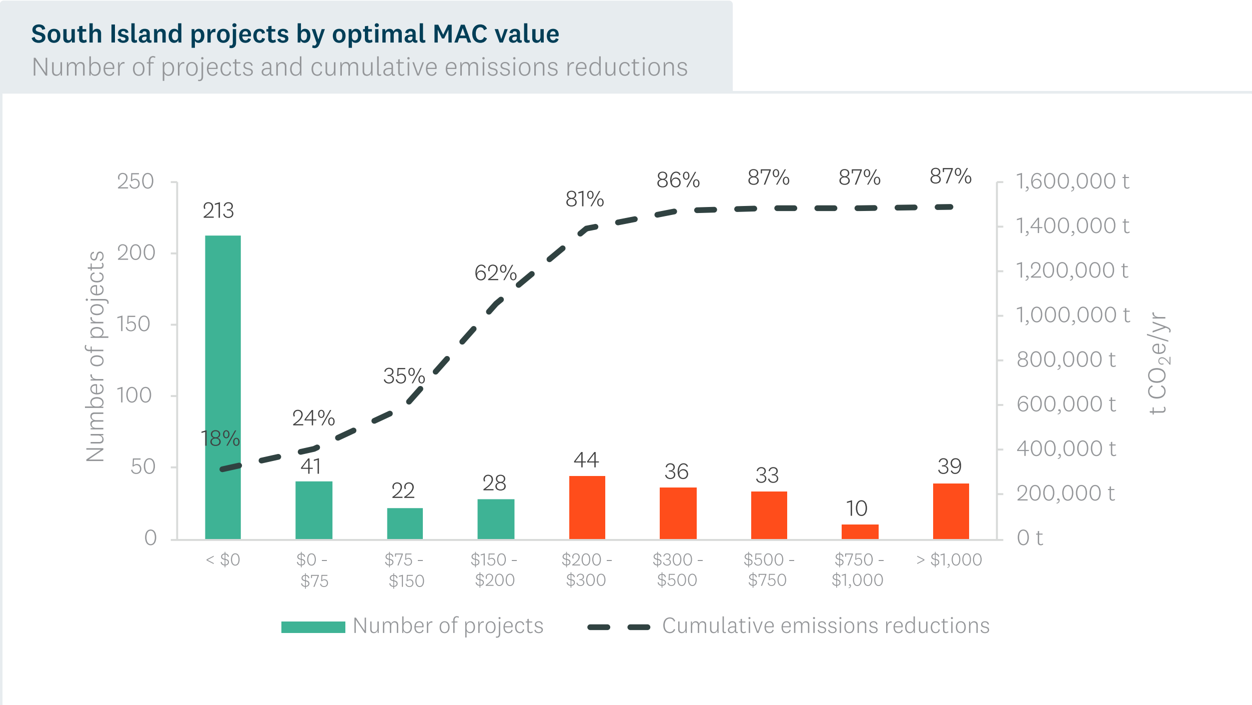
Christchurch, Canterbury, New Zealand. Credit - Ernest Kung.

[12] The full description of the marginal abatement cost calculation used in each South Island RETA region is available in the individual RETA reports.

[13] For nearly all sites, heat pumps were considered to reduce the portion of a site's process heat needs that was <100°C (typically hot water). However, for some sites, heat pumps could be considered as a fuel switching option, i.e. they would be considered alongside electrode boilers and biomass boilers to meet the entire site needs.

[14] Where there were multiple fuel switching options, the chart only shows the MAC associated with the lowest cost option.

Figure 5 – Number of projects by range of MAC value. Source: EECA



400kt of emissions reductions are economic at today's carbon price.

By comparing project MACs with expected future (shadow) carbon prices, they also provide an indication of when each project becomes commercially attractive. Figure 5 shows that 254 projects – delivering over 400kt/year of emissions reductions – would be 'economic' at today's carbon price in the New Zealand Emissions Trading Scheme (~$65/t CO_2e). Notwithstanding the fact that our analysis shows these projects are economic today, these projects may not happen imminently due to a range of well-known reasons (e.g. access to capital). EECA will further explore innovative ways we can help businesses overcome these barriers and execute these projects that, in the long run, will save these businesses money.

A further 600kt of emissions could become economic before 2037.

If the carbon prices in New Zealand increased according to the Climate Change Commission's 2023 Demonstration Path (CCC DP), another 22 projects would be economic at some point between now and 2037, when the use of coal boilers for low-to-medium industrial process heat is prohibited.

This analysis assumes that process heat users execute these projects when the carbon price (in the NZ ETS) reaches the project's MAC value. However, the decision to invest in a new boiler (for example), which is likely to have a life of 15-20 years, should consider both current and future carbon prices[15]. Were we to assume process heat users believe the CCC's Demonstration Path was a good predictor of future carbon prices, the number of projects that would become economic by 2037 would rise to 50, delivering 600kt/year of additional emissions reductions.

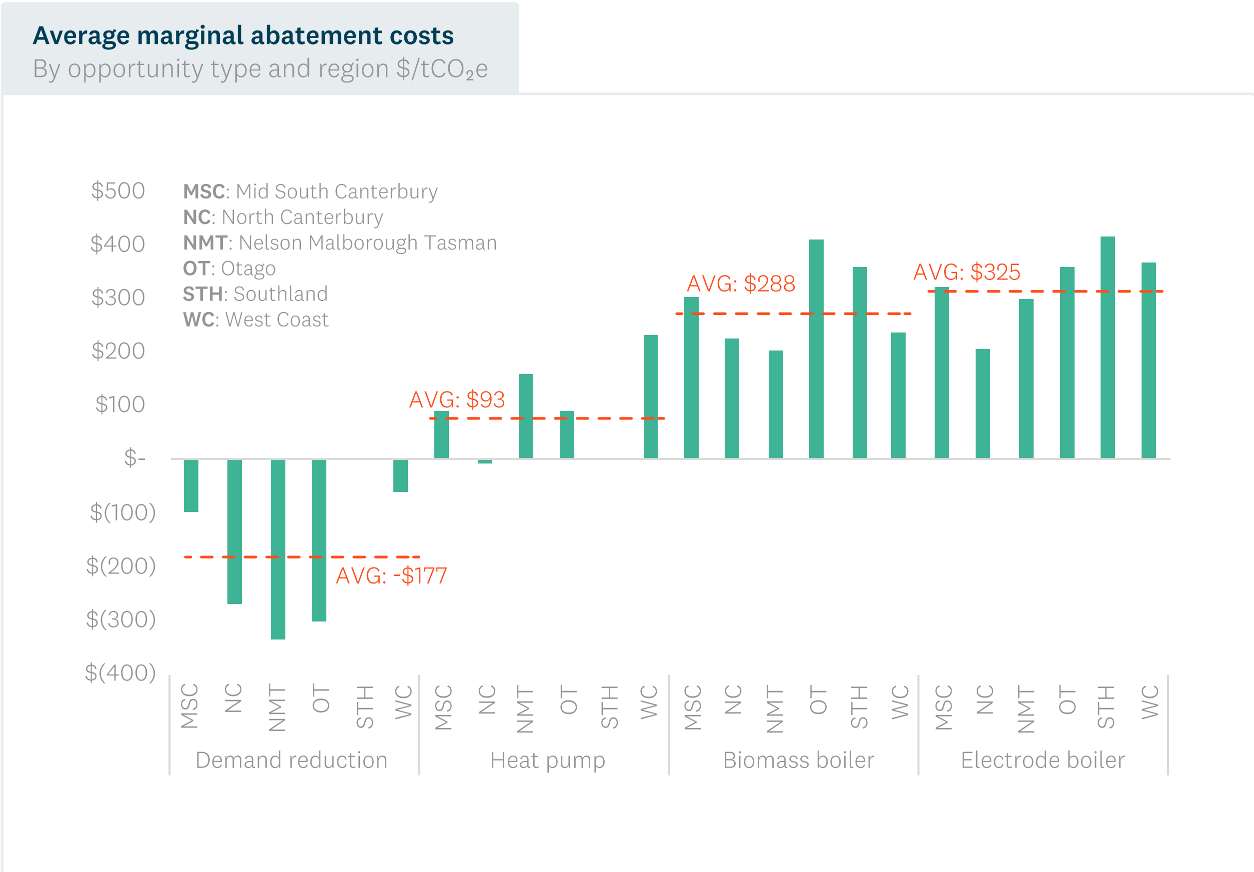
Together with the projects that are economic today, these 304 projects would be delivering 1Mt of emissions reductions per year by 2037, eliminating over 60% of today's process heat emissions across the South Island RETA.

15 This is because future carbon prices will influence the future cost of fossil fuels. As the decision to invest in a low emissions boiler will avoid these future costs, the future carbon price needs to be considered in the investment decision.

5.3 The economics of decarbonisation varies across regions

For fuel switching there are a number of variables which drive the overall economics of decarbonising process heat. Some of these variables are unique to individual regions – biomass and electricity prices, for example – and these can have a significant effect on different types of projects. Figure 6 shows MAC values for different types of decarbonisation projects, across the six regions of the South Island.

Figure 6 – MAC values for of different process heat decarbonisation projects across the South Island[16]. Source: EECA



Demand reduction and heat pump efficiency projects could save $390-585M in capital costs.

Across all regions in the South Island, demand reduction and thermal efficiency projects consistently have the lowest MAC values and are therefore the most commercially attractive projects. They deliver the vast majority of the 400kt of emissions reductions that are economic today. Demand reduction projects often have negative MAC values – meaning that they are commercially attractive even without a carbon price.

16 This is because future carbon prices will influence the future cost of fossil fuels. As the decision to invest in a low emissions boiler will avoid these future costs, the future carbon price needs to be considered in the investment decision.

The net costs to a process heat user for any individual decarbonisation project, which underpins its MAC value, are driven by two primary components:

- **CAPEX** – The capital cost of the low-emissions heat equipment installed.
- **OPEX** – The operational costs associated with the new low-emissions fuel, offset by the cost savings associated with no longer consuming fossil fuels.

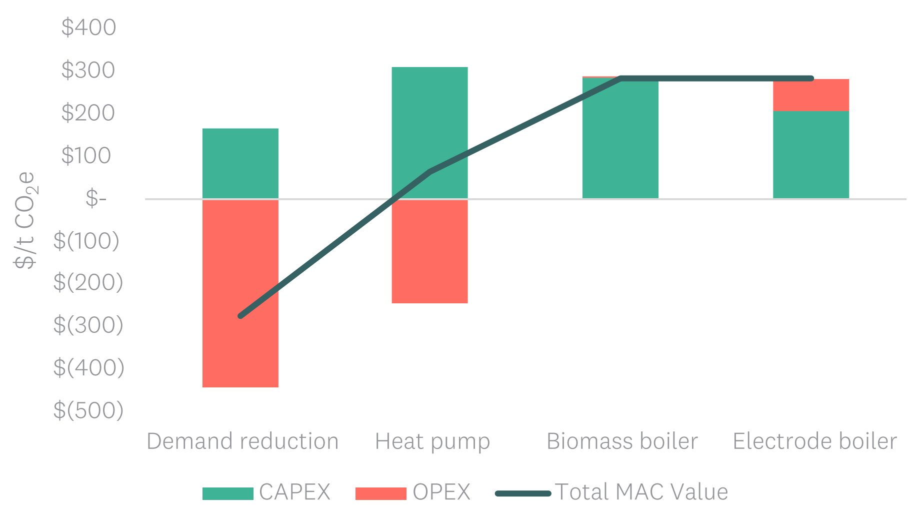
Using these two components of a MAC value, we can explain the general difference in MAC values between the four *types of projects* illustrated in Figure 6, as well as the difference in MAC values between *regions*, in terms of their OPEX and CAPEX components.

Difference in the MAC values between types of decarbonisation projects.

Figure 7 shows how these two components vary, and together result in the overall MAC value for different process heat decarbonisation projects.

Figure 7 – South Island[17] CAPEX and OPEX components of the MAC value of process heat decarbonisation projects. Source: EECA

CAPEX and OPEX components of MAC values
$/t CO_2e



[17] The underlying analysis only decomposed the MAC value into its constituent parts for four regions in the South Island – Otago, West Coast, North Canterbury and Nelson, Marlborough, Tasman. This is due to the fact that the analysis underpinning the first two regional report did not disaggregate MAC values into OPEX and CAPEX.

Figure 7 illustrates that:

- **Demand reduction** projects have relatively low CAPEX, and invariably reduce the cost of purchasing fossil fuels without incurring any 'new' operating costs – hence the OPEX component is always negative. On average, this saving in fossil fuel OPEX more than offsets the CAPEX cost, leading to a negative MAC value.

- **Thermal efficiency** projects have relatively high CAPEX, typically driven by the capital cost of a heat pump. However, the high efficiency of heat pumps – usually in excess of 300% – means that the costs of purchasing electricity is typically more than offset by the savings in fossil fuel costs, again leading to a negative OPEX MAC value. The negative OPEX MAC component sometimes, but not always, offsets the CAPEX MAC component. On average across the South Island, heat pump MAC values are positive, but much lower than electrode or biomass boilers.

- **Biomass boilers** have high capital costs (relative to electrode boilers). Since the average cost of biomass[18] offsets the savings in fossil fuels[19], the overall (net) OPEX component is close to zero.

- **Electrode boilers** have lower initial capital cost (even allowing for the average cost of connecting them to the electricity network), but the cost of electricity – and therefore the OPEX component of the MAC value – is higher than the cost of fossil fuels[20]. The impact of higher electricity costs is partly offset by the fact that electrode boilers are 25% more efficient than biomass boilers, but the overall OPEX component is still higher than biomass in all regions.

The effect of averaging CAPEX and OPEX components of MAC values across the whole island masks significant variation within regions, and between regions. While Figure 7 suggests that, on average, biomass and electrode boilers have very similar MAC values, this is rarely the case on an individual project basis. Figure 8 compares two biomass and electrode boiler fuel switching projects of different scales from the South Island:

- A 15MW industrial project, and

- A 0.5MW commercial project.

[18] As with electricity, there are a number of factors that result in the cost of biomass varying within and across regions. Local availability transportation is one of these, and this is further discussed in Section 6.3.

[19] Note that in a calculation of a MAC, the cost of carbon is ignored.

[20] Again, reinforcing that the MAC calculations ignore the cost of carbon emissions created by the fossil fuels.

Figure 8 – Comparison of two sites' MAC components. Source: EECA

Site 1 (15MW) – MAC components
Biomass boiler

Site 1 (15MW) – MAC components
Electrode boiler

Site 2 (0.5MW) – MAC components
Biomass boiler

Site 2 (0.5MW) – MAC components
Electrode boiler

Figure 8 shows that, for the large site (Site 1), the key difference is the industrial facility has access to an electricity tariff that is lower than the cost of biomass. Further, the electrode boiler is 25% more efficient than a biomass boiler. The site therefore would have to purchase (in energy terms) less low emissions energy to replace the fossil fuels currently being used. This results in an electrode boiler being the optimal choice for the site.

For the small site (Site 2), the primary difference is the fact that, to enable an electrode boiler to be used, the process heat user needs to invest $1.4M in a larger capacity connection to the local network. This is a fixed cost and is high relative to the small consumption from the site, as indicated by the $852/t CO_2e component of the MAC value. Since there is no corresponding 'network upgrade' cost for the biomass boiler, it is the preferred choice.

The illustration of a 'small site', and the significant impact of fixed costs on MAC values, points to a general challenge with sites that have low utilisation. Large industrial facilities typically use their full heat capacity most of the time, and therefore can spread the fixed costs associated with emissions reductions (e.g. boiler purchases and network charges) across large volumes of energy[21]. Smaller sites often use heat for only part of the year – for example, space heating a facility (such as a school) may only be required in winter. Fixed charges will still be material, driven by the capacity of the heating plant, but will be spread across a relatively small amount of energy usage.

Regional differences in MAC values

While factors such as the estimated efficiency and capital costs of boilers and heat pumps were applied consistently across all regions, the per-unit costs of biomass and electricity were calculated specifically for each region based on local factors. For electricity, this included the retail price of electricity, network charges and the cost of connecting to the network (including any upgrades required).

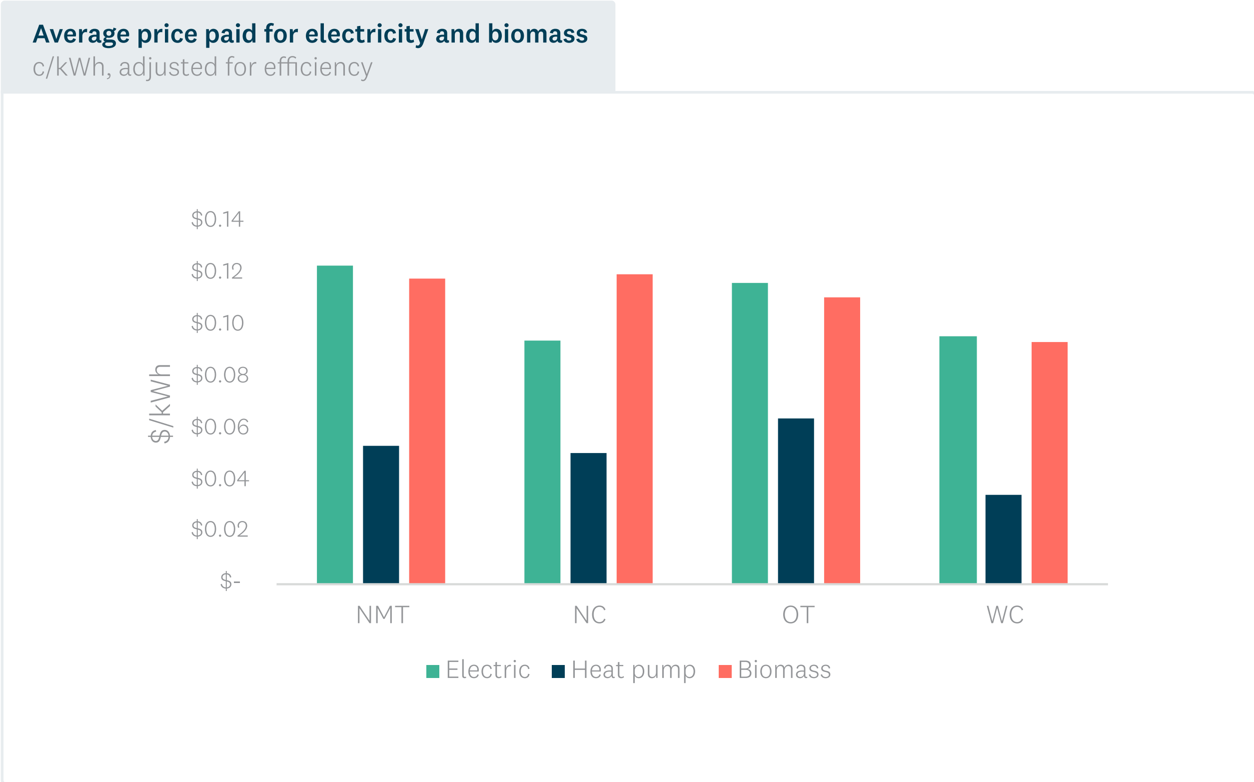
Figure 9 shows, for four regions[22], the volume-weighted average price paid for electricity and biomass by process heat users. The prices in Figure 9 have been adjusted to reflect the different efficiencies of each technology[23]. The electricity price includes network charges, but not any capital costs associated with network upgrades required to accommodate the connection (see below).

[21] For the calculation of MAC values, large volumes of energy correspond to high quantities of emissions reductions, which are the denominator in the calculation of a MAC.

[22] See previous footnote regarding why we only present this MAC breakdown for four South Island regions.

[23] Showing the underlying absolute electricity and biomass price paid would paint an incorrect picture of the relative economics of the two fuels, since heat pumps are 350% efficient and electrode boilers 99% efficient, compared to biomass boilers (80% efficient).

Figure 9 – Volume-weighted average electricity and biomass price paid for heat pumps, electrode, and biomass boilers. Source: EECA

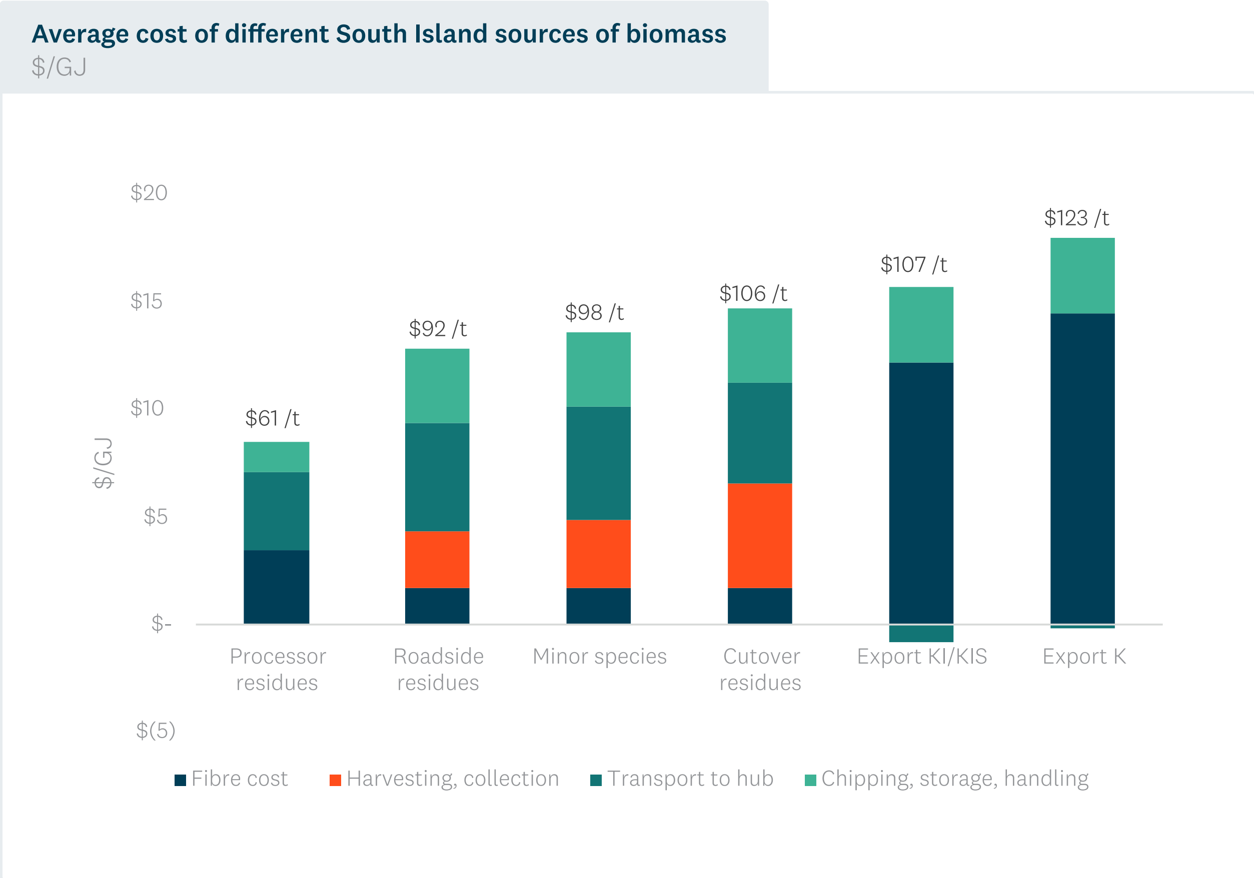


These prices are volume-weighted average prices and reflect different mixes of process heat users in each region. Industrial process heat users had access to lower electricity tariffs than smaller commercial users (such as hospitals and schools) – interpreting the absolute levels of prices is challenging due to the different proportions of small and large sites included in each region.

The underlying drivers of biomass MAC values

Figure 10 shows the costs of collection of the available resources, delivery to a central processing and storage 'hub' and processing the resources into woodchip. Also shown on the chart are the costs of export-grade logs, to illustrate the potential impact on biomass prices should demand exceed the available supply of lower cost residues and minor species.

Figure 10 – Estimated delivered cost of potential bioenergy sources. Source: Ahikā and Margules Groome (2023)



These costs were used for all regions. However, the availability of each of the potential resources in Figure 10 varied between regions. Equally all regions are already utilising some amount of these resources (e.g. for domestic firewood). This varying availability of different biomass sources for new process heat users meant that the expected regional cost of biomass (delivered to a hub) varied between $13.50/GJ and $23/GJ[24].

Finally, the delivery costs of the processed biomass to each individual process heat user needs to be accounted for. In most regions, all process heat users were found to be within 60km of the identified hub, which added $2.50/GJ to the above costs. However, in some regions the distances between some process heat users and a central hub were greater, and transport costs were adjusted.

Section 6.3 explores the potential for transporting biomass from relatively low-cost regions to high-cost regions, which has further implications for the overall cost paid by process heat users.

[24] Further costs of processing (into dried woodchip or pellets) were assumed to be identical in each region, as was an assumed $3/GJ margin for the various parties involved in collecting, storing, and processing biomass into a usable form.

The underlying drivers of electricity MAC values

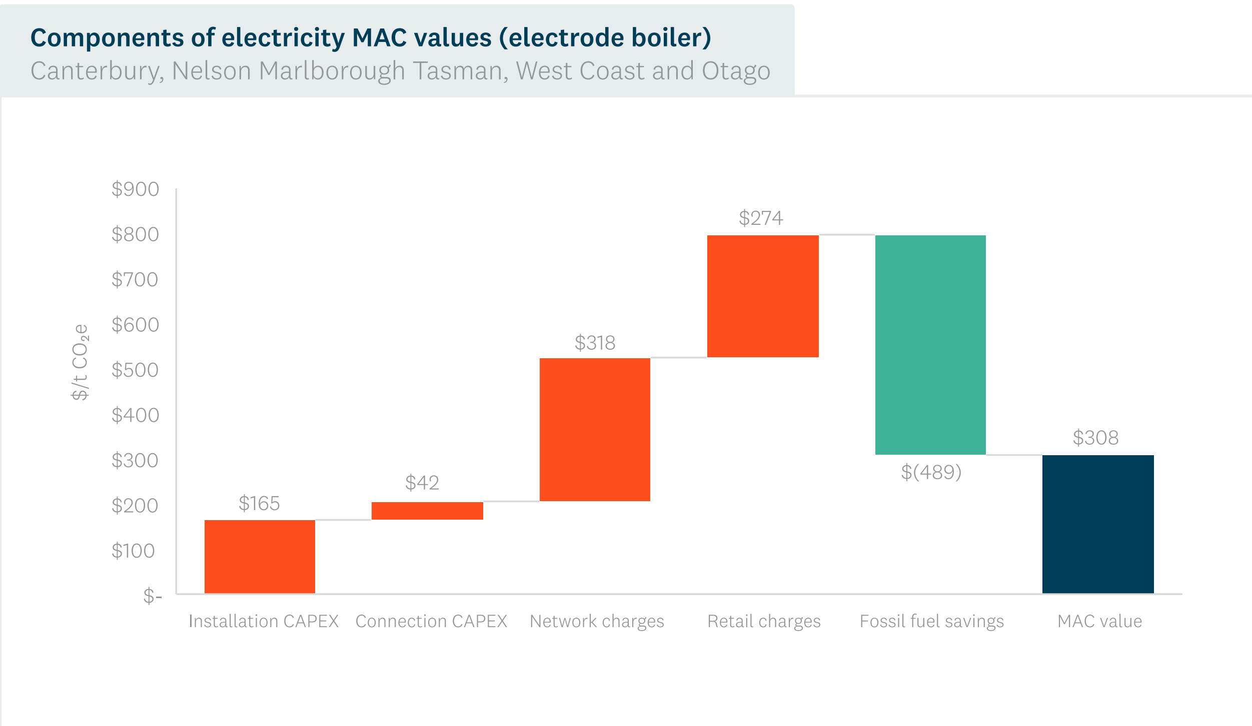
On average, ongoing electricity retail and network charges are the largest components of marginal abatement costs for fuel switching using electricity.

The cost of switching to an electricity-based heat plant (heat pump or electrode boiler) has more components than biomass[25], in addition to the cost of purchasing the boiler or heat pump. Costs include:

- The retail charges of purchasing the electricity.
- The charges paid to the EDB for the use of their network.
- Capital costs associated with expanding the site's connection to the grid (if required), and any deeper upgrades required because of the connection.

Figure 11 shows the relative impact of each of these components on the average electricity MAC value, for four regions of the South Island.

Figure 11 – Components of MAC values for electrode boiler projects. Source: EECA



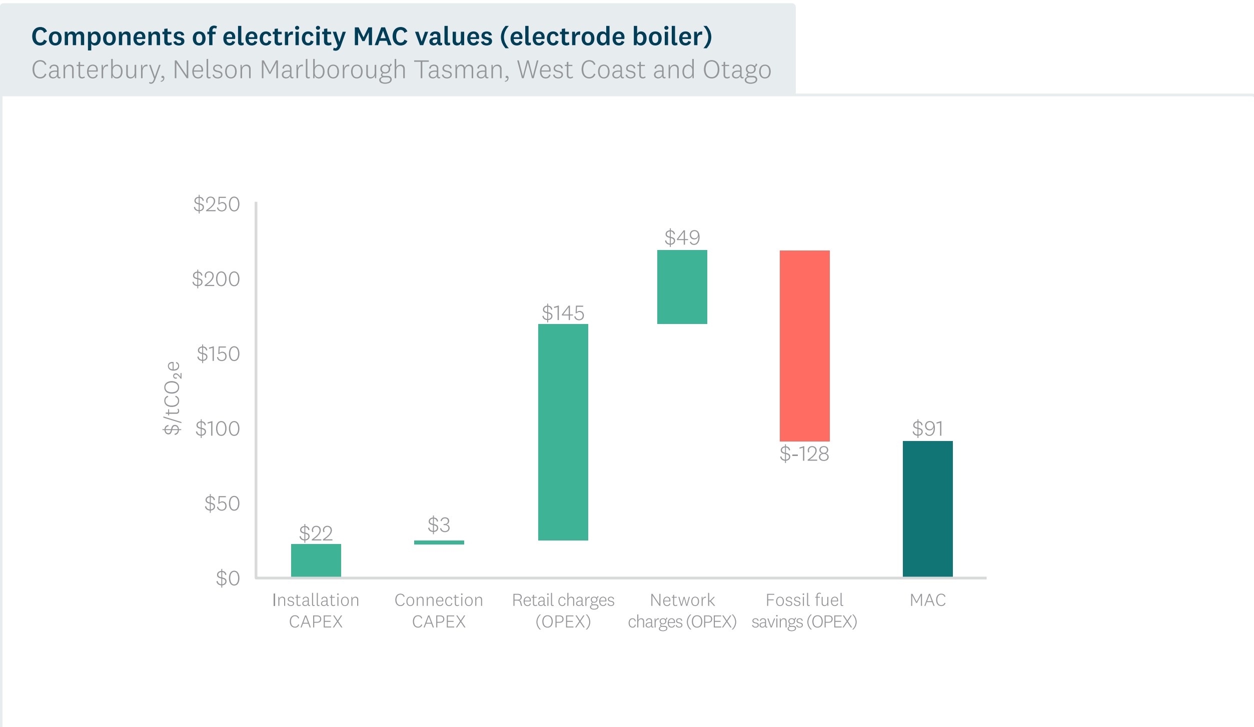
25 Biomass does have analogous charges, but these tend of be variablised and bundled. For example, the costs of access to the roading 'network' are variablised as road user charges and bundled into the 'transport' cost (see later). Arguably, the costs of providing additional onsite storage for biomass (due to its lower energy content compared with coal) is analogous to connection costs for electricity.

In the long term, network and retail charges play a much more dominant role in electricity MAC values than the upfront capital cost associated with the boiler or network connection. On average, the cost of network charges (for use of the existing network) is nearly an order of magnitude larger than the average capital cost of any upgrades required to connect to the network[26].

Fixed network-related charges play a more significant role in MACs for small sites with low heat plant utilisation than in larger industrial sites. It is vital that all process heat users (particularly smaller sites and/or those with low utilisation) investigate how to minimise the total capacity required from the new heat plant.

The averaging in Figure 11 disguises the role that electricity charges play in individual MAC values for the wide range of sites investigated in the South Island. To illustrate, in Figure 12 we show the electricity MAC component breakdown for the same two sites illustrated above in Figure 8. However, for the smaller site (Site 2), we show the MAC value for both an electrode boiler and a heat pump[27].

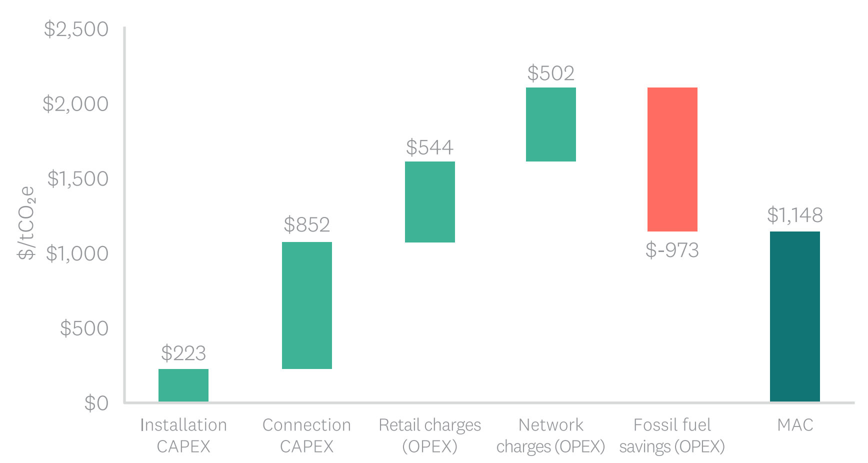
Figure 12 – Components of electricity MAC values for boilers and a heat pump. Source: EECA



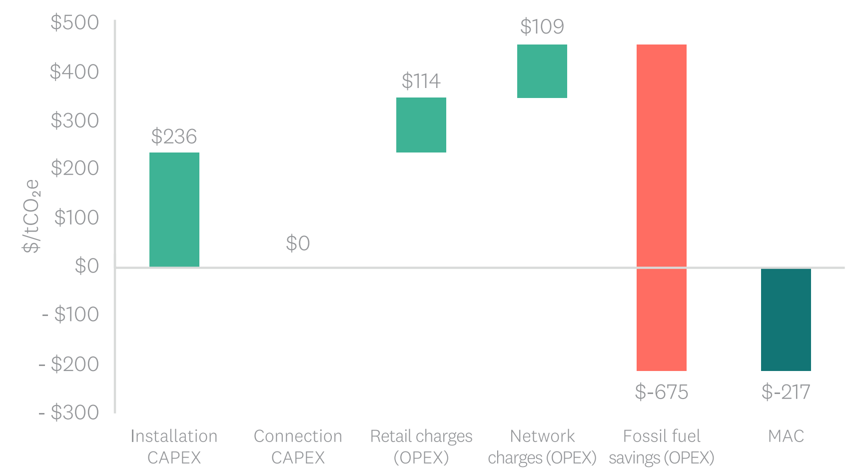
26 The connection CAPEX charges in this chart are adjusted for an assumed capital contribution proportion of 50% - i.e. the EDB and the customer share the cost of connection CAPEX equally. Each individual EDB has its own capital contribution policy, the results of which may lead to a variety of cost sharing arrangements.

27 A heat pump wasn't a feasible option for all of site 1's process heat needs, i.e. the component of heat needs that exceeded 100°C.

Components of electricity MAC values (electrode boiler)
Canterbury, Nelson Marlborough Tasman, West Coast and Otago



Components of electricity MAC values (electrode boiler)
Canterbury, Nelson Marlborough Tasman, West Coast and Otago



As outlined above, the need for investment in the network (connection CAPEX) to accommodate the new plant can have a spectrum of impacts on the MAC value – while both the large and small electrode boiler require connection investment of between $1.3 and $1.5M, the highly utilised large boiler can spread that cost across a large quantity of emissions reductions compared to the small boiler.

Figure 12 also highlights the differing impacts of retail charges (which are charged per kilowatt-hour of consumption) and network charges (which have significant fixed components) on MAC values. For the large boiler, network charges have only a third of the impact of retail charges, while the respective impacts of retail and network charges is similar for the small sites.

Finally, Figure 12 also shows the significant impact heat pump efficiency has on MAC values. A heat pump can produce the same heat output of an electrode boiler 3-4 times its size but requires only 25-30% of the retail electricity purchases and network capacity. While the upfront cost of the heat pump equipment and installation is slightly higher, the overall MAC value is much lower, whilst achieving similar degree of emissions reductions[28].

Overall, Figure 12 shows that individual MAC values, reflecting a particular process heat user, and a particular location in the network, can vary substantially across the region.

Given the potentially significant impact of retail and network electricity charges – especially those aspects related to the capacity of the connection or peak demand – it is vital that all process heat users (particularly smaller sites and/or those with low utilisation) investigate how to minimise the total capacity required from the new heat plant, and therefore the network.

As discussed above, investing in demand reduction and the use of high-efficiency heat pumps (for water and space heating needs) are almost always economic ways to reduce the peak demand of their site. In Section 6.2, we demonstrate the potential value of flexibility to the process heat user from reducing these charges.

[28] This may not always be the case. In the case illustrated here the heat pump was 850kW (output), and did not trigger any need for additional network capacity. As industrial heat pumps get larger than this, connection CAPEX can be triggered.

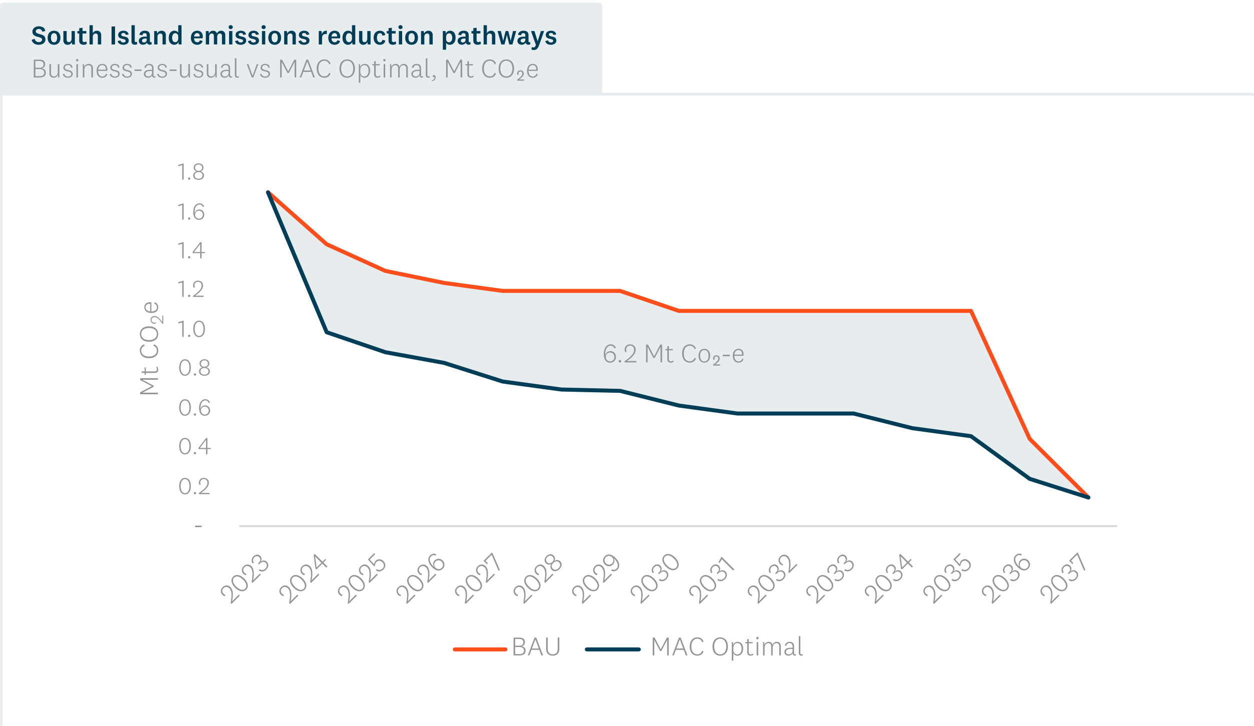
Azwood, Nelson, New Zealand.

6 South Island pathways show the acceleration potential

Commercial decision-making about investment in decarbonising South Island process heat could accelerate emissions reductions, reducing the cumulative release of long-lived emissions by 6.2Mt between now and 2037.

MAC values calculated for the South Island RETA allow us to explore different pathways of emissions reductions. Compared to a scenario where each of these projects used the fuel with the lowest MAC value, but timed its execution based on the organisations' current plans (the BAU pathway described in Section 4.3), executing these projects using the MAC decision-making criteria outlined above ('MAC Optimal') would accelerate decarbonisation (Figure 13).

Figure 13 – Simulated emissions using BAU and MAC Optimal pathways. Source: EECA



Some emissions remain in 2037, primarily because of the small amounts of CO_2 left in grid-connected electricity generation[29]. Despite these residual emissions, and compared to the BAU pathway, the MAC Optimal pathway would reduce the cumulative release of long-lived emissions by 6.2Mt over the period of the RETA analysis to 2037.

The MAC optimal pathway assumes that process heat users will execute their investments in demand reduction, thermal efficiency and fuel switching as soon as their expectations of the 10-year forward average of carbon prices exceeds the MAC value of the investment. In reality, organisations' decisions are driven by a range of factors, such as access to capital, expectations of customers and internal priorities. While we cannot model these factors, we have modelled a further critical factor – their expectations of the carbon price.

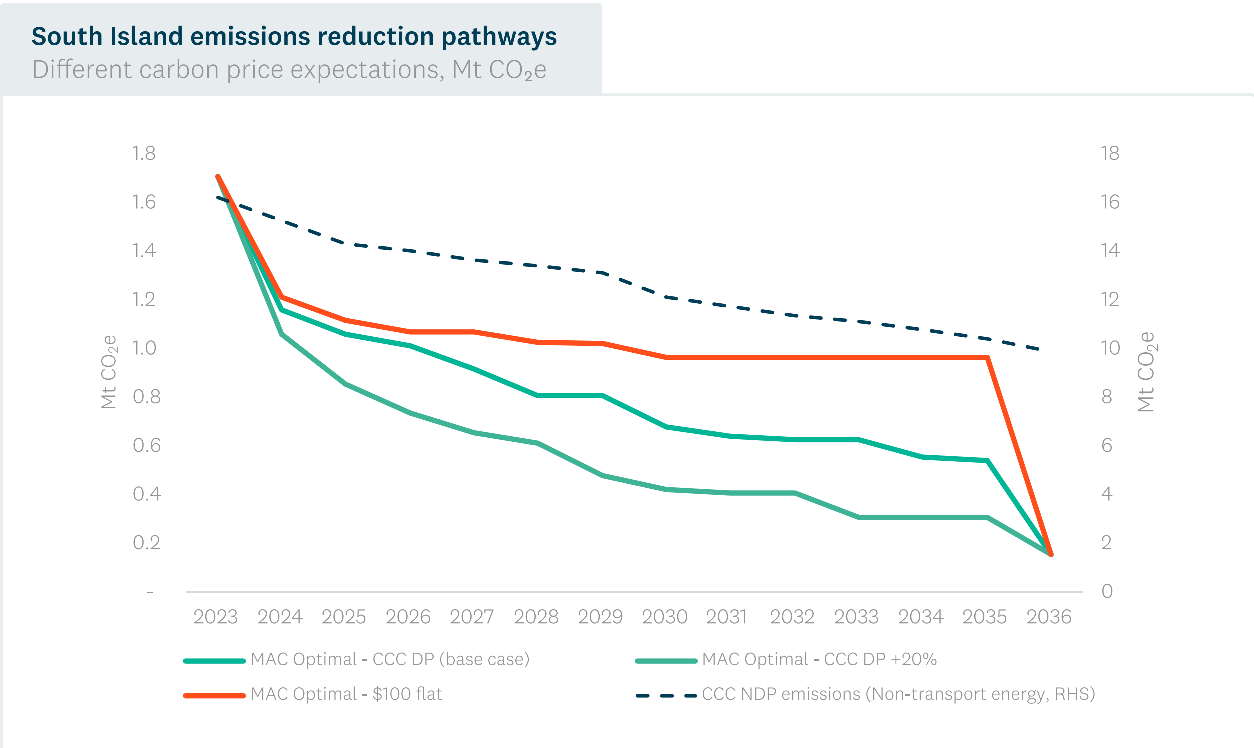
While the MAC Optimal pathway is based on the CCC's recent Demonstration Path, there is no guarantee that:

- Actual carbon prices (in the NZETS) will follow the CCC's Demonstration Path, or
- Process heat users will believe that prices will follow the CCC's Demonstration Path.

Figure 14 illustrates how South Island process heat emissions reductions change (under the MAC Optimal pathway) for different process heat users' expectations of the carbon price, including:

- The CCC's Demonstration Path shadow carbon prices (base case)
- Carbon prices will be 20% higher than the CCC's Demonstration Path
- An expectation that the carbon price will not exceed $100/t over the period.

Figure 14 – MAC Optimal emissions pathways: different carbon price trajectories. Source: EECA

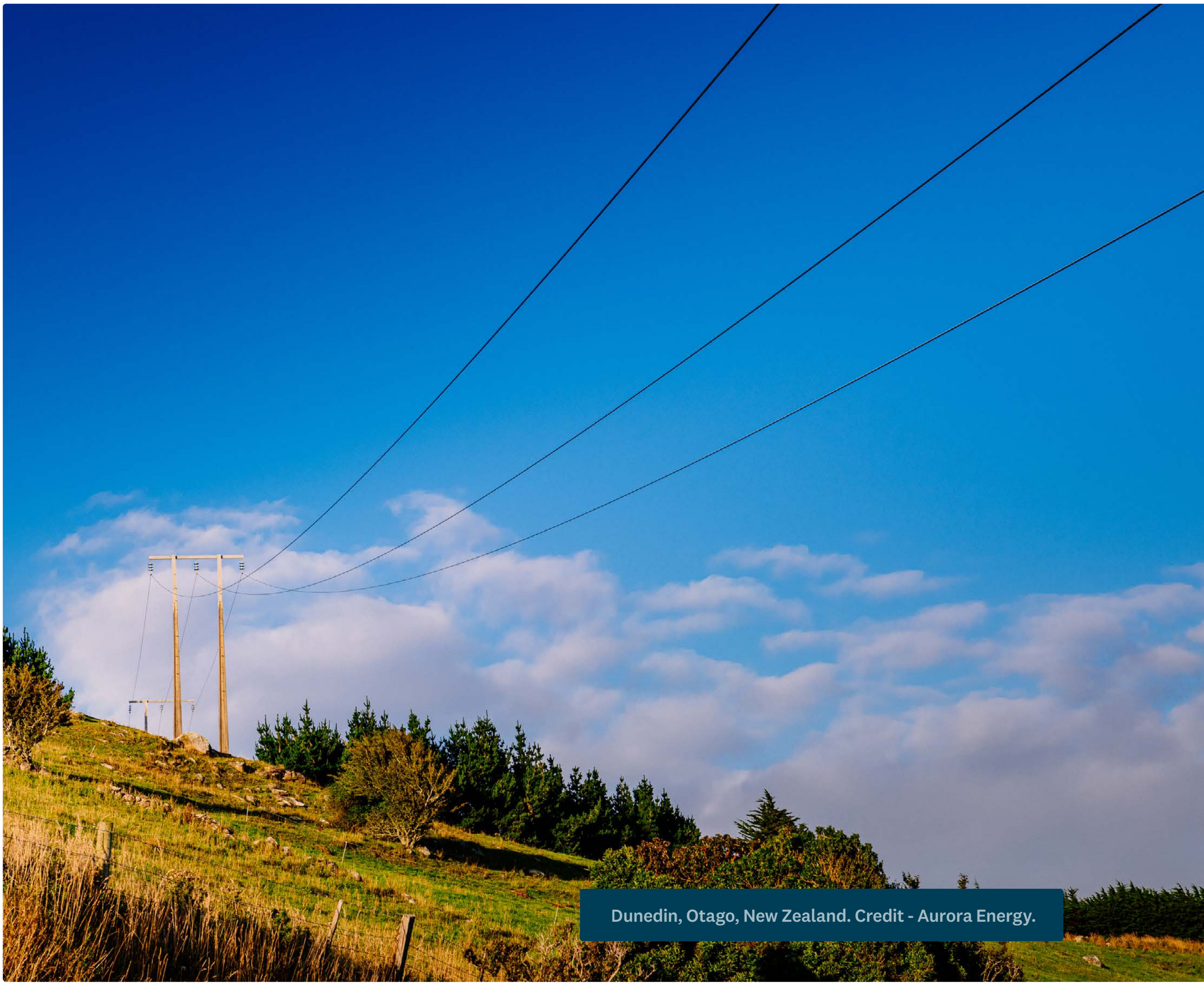


[29] Even in a very high renewables electricity system, some CO_2 emissions remain from geothermal generation, although we note that the major NZ geothermal owners have recently reported successful carbon capture pilots from some existing geothermal plants. As a result, emissions reductions could be even greater in reality than shown in this figure.

Figure 14 also shows (on a different scale) the trajectory of non-transport energy emissions that occurs under the CCC's Demonstration Path. This shows that, under the CCC-based carbon price trajectories, emissions reductions in process heat in the South Island broadly achieve the pace required under the CCC's path.

However, if carbon prices remain around $100/t, other than a set of projects that are either confirmed or very economic today, further emissions will not keep pace with the CCC's emissions path[30].

Similarly, once confirmed projects are executed, as long as process heat users believe the medium-term price of carbon will remain around $100/t, very little additional progress will be made on the decarbonisation of process heat. This highlights the importance of process heat users' confidence in the NZ ETS if they are to make commercial decisions that deliver to New Zealand's climate commitments.



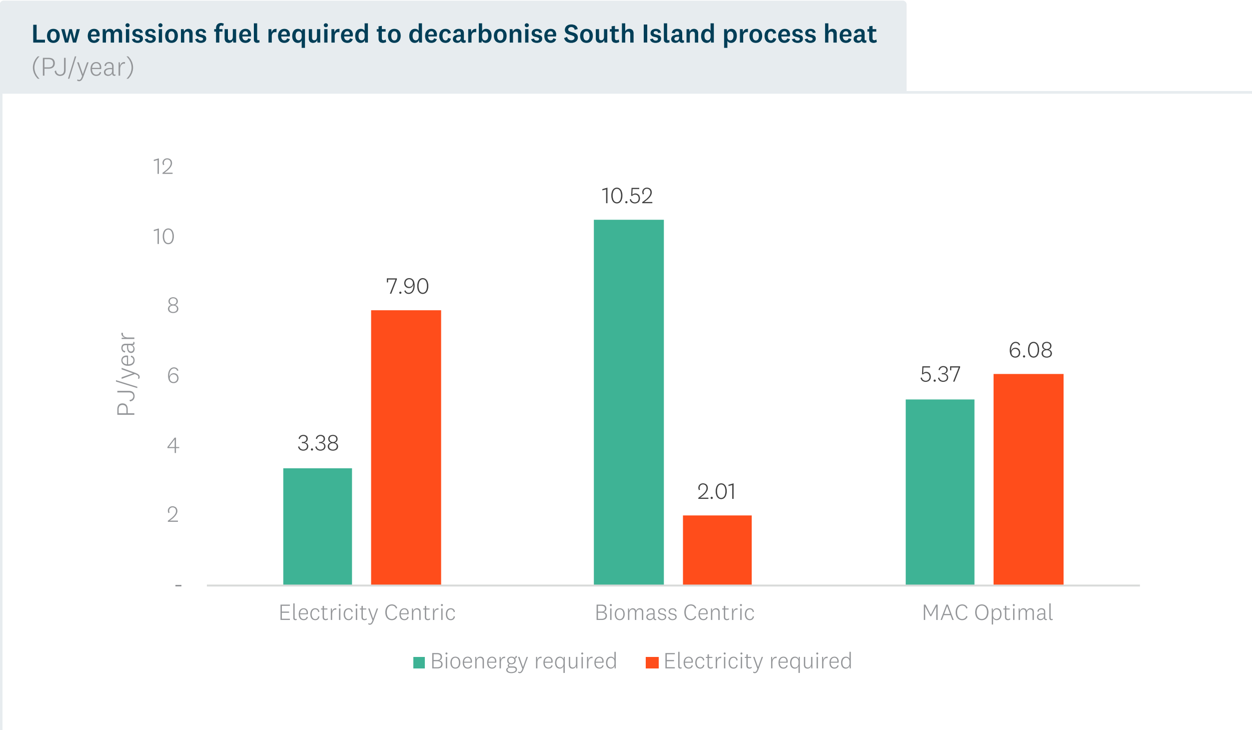
Dunedin, Otago, New Zealand. Credit - Aurora Energy.

[30] Except, of course, in 2037, where all remaining coal-based projects are required to occur as a result of the NPS, as outlined above.

6.1 What emissions reductions mean for low-emissions fuels in the South Island

The decisions made by organisations as to which low-emissions fuel to switch to (biomass or electricity) could have significant impacts on the markets for those fuels. Figure 15 shows the resulting fuel demand (in 2037) from two 'outlier' scenarios, as well as the MAC-based decision-making criteria ('MAC Optimal'). The outlier scenarios assume that all unconfirmed fuel switching decisions choose biomass ('Biomass Centric') or electricity ('Electricity Centric')[31].

Figure 15 – Electricity and biomass demand in different pathways, 2037. Source: EECA



As shown earlier in Figure 4, 73 decarbonisation projects are confirmed to proceed by process heat users. The confirmed projects will create 2PJ of new demand for electricity (28 projects), and 3.4PJ of new demand for biomass (45 projects).

Fifteen of these projects were confirmed since the RETA process commenced in 2022. Thirteen of these recent confirmations have chosen electricity as their low emissions fuel. Seven of these sites chose electricity despite our analysis of MAC values (done for the regional reports) suggesting biomass was the lowest cost decarbonisation option, although we note that in some cases the difference between the biomass and electricity MAC was under $70/t. As shown by the various sensitivity analyses (detailed in the regional reports), plausible changes in input costs (electricity connection and network charges, the use of demand flexibility, or the delivered cost of biomass) could cause changes in relative MAC values of this order. This reinforces that, when individual organisations finalise fuel switching decisions, they do so with the latest information available to them, including a range of factors not able to be modelled in our regional reports.

31 The fact that there is still some electricity use in the Biomass Centric pathway, and biomass use in the Electricity Centric pathway, is a result of projects that have already been confirmed, and that a small number of sites only contemplate one fuel switching option.

Energy efficiency accounts for 32–39% of the reduction in fossil fuels in the South Island RETA

Finally, Figure 15 allows us to quantify the impact of energy efficiency in the South Island RETA. The combined energy demand for low emissions fuels in each of the pathways is substantially less than the 2022 baseline of fossil fuels consumption (18PJ). The difference, which ranges between 5.9PJ to 7.1PJ of energy, representing 32–39% of the baseline fossil fuel use, arises from:

- Demand reduction
- The use of highly efficient heat pumps for low temperature heating needs, and
- The improvement in fuel efficiency achieved from moving from coal boilers (78% efficient) to biomass (80% efficient) and electrode (99% efficient) boilers.

78% → **80%** → **99%**

Coal boilers
(78% efficient)

Biomass boilers
(80% efficient)

Electrode boilers
(99% efficient)

Hanmer Springs, Canterbury, New Zealand. Credit - MainPower.

6.2 Implications for the electricity system

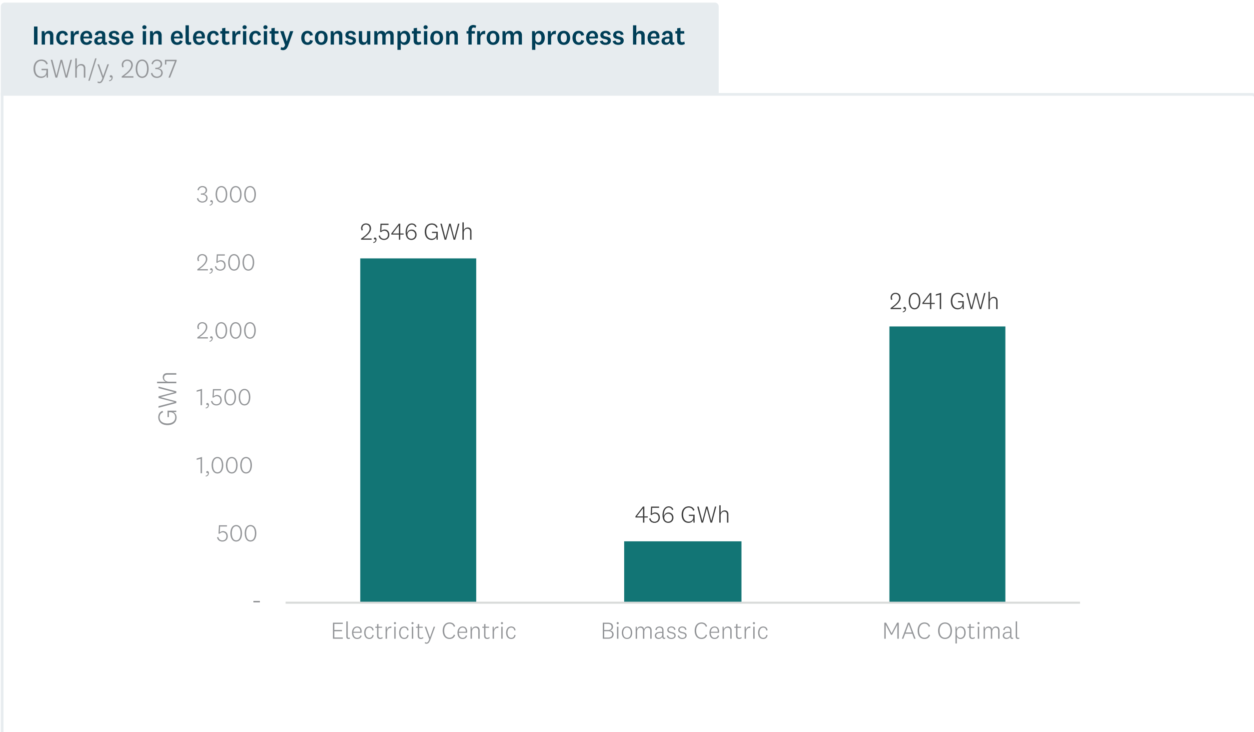
Between now and 2037, the MAC Optimal pathway requires $2B of renewable generation investment, up to $1B of peaking generation or storage, and triggers $207M of transmission and distribution investment.

Implications for electricity generation investment

The MAC Optimal pathway will require over 2,000GWh of investment in new generation – likely to cost around $2B – over the next 13 years to meet the new electricity demand requirements from South Island process heat users.

Just over half of this is required by 2028.

Figure 16 – Additional South Island electricity consumption in 2037. Source: EECA



The increase in electricity consumption by 2037 is relevant to the amount of extra generation that will be required to support these decisions. To put Figure 16 in context, the extra 2,041GWh of electricity consumption in the MAC Optimal scenario, in 2037, represents 12% of today's South Island consumption[32].

32 15,158GWh. Source: emi.ea.govt.nz.

However, the MAC Optimal pathway requires 1,100GWh per year of additional generation (6-7% of South Island demand today) **in the next four years**. This is equivalent to the annual output of a 300MW wind farm, or a 600MW solar farm, either of which are **likely to cost around $1B**. While a recent Electricity Authority report* suggests that 5,000GWh of generation investment is *committed* over the next 3-5 years, much of this is expected to be offset by generation retirements. More of the 'actively pursued' generation projects flagged in the Authority's report would need to be built in order to meet the near-term MAC Optimal process heat conversions.

By 2037, the investment requirements from the MAC Optimal pathway grow to 2,041GWh, requiring around $2B[33] of renewable generation investment; equivalent to the annual generation from around 750MW of wind farms, 1,500MW of solar farms or 300MW of geothermal power stations.

If all electrifying process heat users reached their peak demand during the overall system peak, it would require an increase in New Zealand's generation capacity of 500MW. If this increase in system capacity was delivered by grid-scale batteries, this would require $1B of investment.

Figure 17 shows that, should all process heat users that switch to electricity reach their 'peak' demand at the same time, it could add between 95MW and 790MW to the market demand at that point in time, depending on the pathway. To put this in context, the combined peak demands from electrified process heat users in the MAC Optimal pathway would add around 20% to South Island peak demand, or 7% to national peak demand, if all of these process heat users reached their peak demands at the same time as the island, or country, reached its peak (typically a weekday morning or evening in winter)[34].

* A recent analysis released by the Electricity Authority[a] reported that around 5,000GWh of generation investment (nationally) is committed within the next 3-5 years. However, the report noted that:

- This is only slightly more than what is required to offset the expected retirement in thermal and geothermal generation over the same period, and more would be required to meet substantial increases in demand.
- An additional 20,800GWh of generation projects are being 'actively pursued' and could be ready to be built in the next 3-5 years, but that these investments are likely to be 'demand-led'.

This is more than sufficient for our identified MAC Optimal process heat growth, but this investment must also provide for any underlying demand growth from other households and businesses, including continued uptake of electric vehicles.

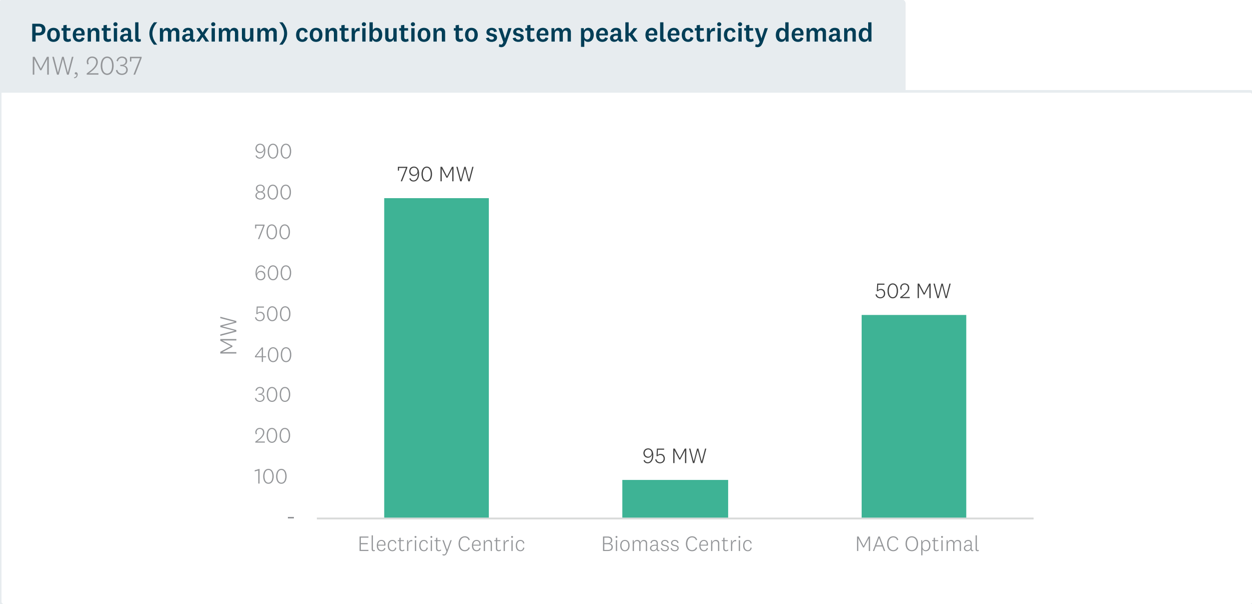
While around 6,000GWh of these 'actively pursued' projects are located in the South Island, the national transmission grid means that not all of the South Island process heat demand requirements need to be delivered by South Island generation. However, relying on generation investment in the North Island will place greater demands on the inter-island HVDC connection.

33 Concept Consulting (2024), 'Generation Investment Survey: 2023 update', available at ea.govt.nz. We use Concept's 2023/24 long-run marginal cost figures of $86-104/MWh, as published on page 5.

34 Peak South Island demand in 2023 was 2,430MW, and occurred on 2nd August at 9:30am; national peak demand was 7,304MW and occurred on 11th August at 6:30pm. Source: emi.ea.govt.nz.

a Concept Consulting (2024), 'Generation Investment Survey: 2023 update', available at ea.govt.nz

Figure 17 – Potential process heat contribution to peak demand in 2037. Source: EECA



However, our regional analysis suggested this was unlikely to occur. The natural diversity in electricity demand behaviour – both between different process heat users, and between process heat and other electricity consumers – led to the combined peak demand (often referred to as 'coincident maximum demand', or CMD) at individual grid exit points (GXPs) often being 8-10% lower than the simple summation we present above. This was particularly true of GXPs that had large dairy factories connected to them, which typically have their periods of lowest demand during the winter months, unlike commercial space heating which is likely to peak in winter. Aggregating across the many GXPs in the South Island will increase this diversity, further lowering the overall impact on peak demand. This means that, in all likelihood, the peak demand in Figure 16 overstates the impact on peak demand.

Regardless, the potential contribution to peak electricity market demand is still likely to be in the hundreds of MW's in the MAC Optimal and Electricity Centric pathway. Again, like consumption, the MAC Optimal pathway sees more than half of its ultimate peak demand (273MW) occur by 2028.

Keeping pace with growth in peak demand is a critical requirement for the electricity market. Currently, a number of generator-retailers in New Zealand have announced plans to deploy hundreds of MW's of grid-scale batteries, which could help with meeting peak demand[35]. In the event that the MAC Optimal electricity demand in Figure 16 eventuates, it would require around $1B of grid-scale batteries to accommodate it, if it occurred at the system peak[36].

This analysis reinforces the importance of electricity fuel switching projects being well signalled to the generation investment market. Investment will occur when generation investors are confident that demand for their output will materialise. This report is the start of clearly signalling the requirements from process heat users. As outlined earlier, it is EECA's intention to complement this with similar analyses of transport energy and capacity requirements.

35 See announcements from Meridian, Genesis, Contact. Contact indicated that its 100MW battery investment is proceeding to final investment decision in FY24.

36 As indicated above, this is a conservative assessment based on the simple summation of individual plant peak demands. The cost estimate is based on the cost of Meridian's Ruakaka investment in a 100MW/200MWh battery storage system ($186M). See https://etn.news/buzz/meridian-ruakaka-battery-energy-storage-new-zealand

The MAC Optimal pathway will require $39M of transmission investment and $168M of distribution investment by 2037.

Investment required in the transmission and distribution network is driven by the degree to which new electrified process heat drives increases in peak demand on those assets. The implications of Figure 17 for transmission and distribution investment involve a range of considerations:

a) As discussed above, the impact of the different pathways on the core South Island grid backbone (including the HVDC) depends on the degree to which all electrode boilers and heat pumps reach their maximum output at the same. The benefit of the natural diversity in underlying demand behaviour will soften the impact of new electrode boilers and heat pumps on core grid assets.

b) At the other end of the spectrum, the peak demand from some individual boiler and heat pumps will trigger investment in the network assets near to their point of connection, because these individual boilers and heat pumps are sufficiently large (by themselves) to trigger local investment, and the benefits of diversity are small, and sometimes zero.

c) Between (a) and (b) there are a spectrum of local and regional network impacts on existing networks which depend on the diversity between heat demands.

d) Depending on the nature of the underlying process, process heat users may have degrees of flexibility as to when they reach their maximum electrical demand. Retail products are emerging that will allow process heat users to 'smartly' shift their demand in response to signals from the electricity market or from distributors, thus reducing the degree of network investment required. The potential for flexibility to reduce the level of network investment required is explored further below.

e) Some sites may have a choice between levels of connection security (N or N-1). N-1 security[37] connections have, by definition, a degree of redundancy in them and are thus more costly. Generally, our approach assumed that process heat users would invest in a connection which preserved the level of security they currently have. However, it is entirely plausible that some sites may choose to adopt a lower (if currently on N-1) or higher (if currently on N) security level if the trade-off between cost and risk is acceptable.

The South Island RETA identified potential transmission and distribution investments that would be needed to accommodate electrified process heat demand for each pathway (Table 1)[38]. These estimates of investment requirements incorporated diversity in peak demand to the extent possible with the available data, assumed process heat users maintained their current level of connection security (as described in (e) above), and did not model the use of flexibility by any individual process heat user.

[37] N-1 allows for the loss of a connection asset whilst maintaining supply to the customer. N security means that when the connection asset fails, the customer loses power.

[38] The reality of electricity networks is that the investment required to meet new peak demands will vary significantly depending on what part of the network each site is located in. This is largely due to the fact that each part of the network is likely to be at different phases in its asset management lifecycle and will experience different patterns of demand depending on the mix of consumers.

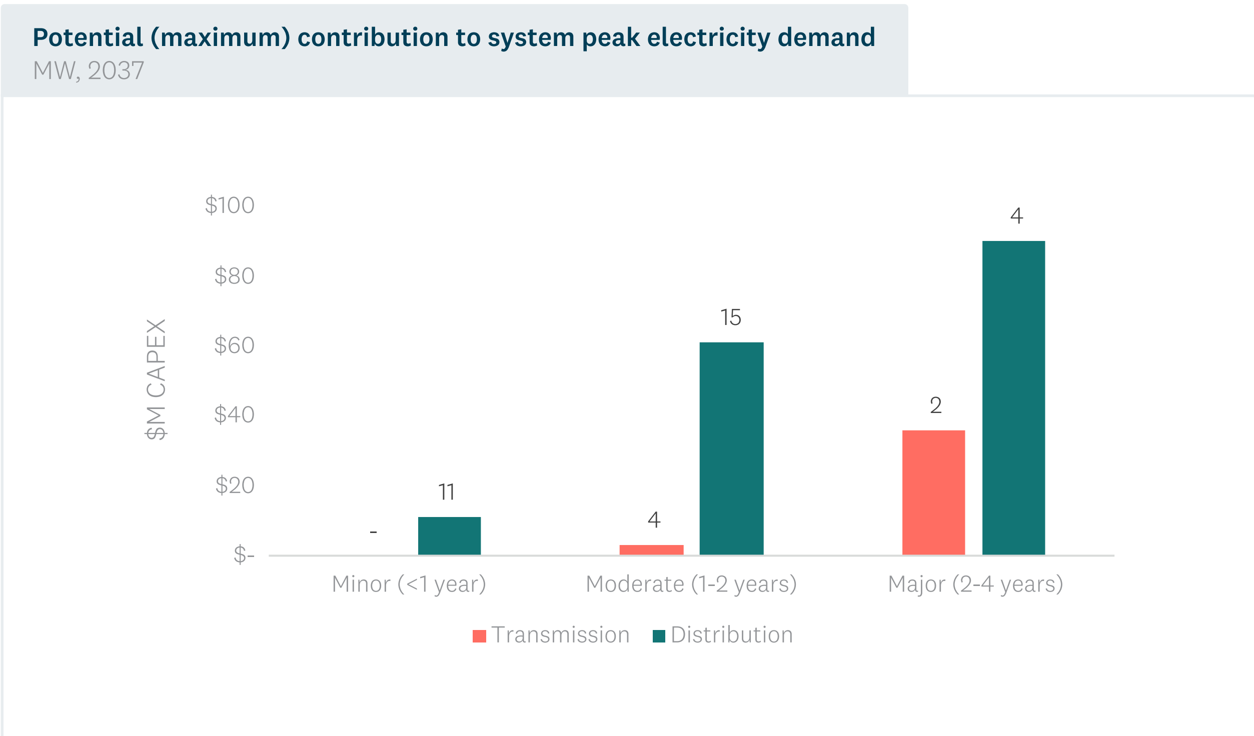
Table 1 – Modelled network investment required for different South Island pathways. Source: EECA

	Electricity Centric – $442M		MAC Optimal – $207M	
	Transmission	Distribution	Transmission	Distribution
Investment	$172M	$269M	$39M	$168M

The regional reports also highlighted a number of transmission investments that will be largely driven by the collective decisions of both process heat users and the wider group of households and businesses as they both grow in number, but also make choices to switch away from fossil fuels to electricity (e.g. electrified transport). Few of these investments are included in Table 1, due to the complexity of determining the degree to which process heat users 'caused' these investments, and/or how the costs would be allocated to process heat users via the sector's Transmission Pricing Methodology.

The MAC Optimal pathway requires approximately half of the investment required by an Electricity Centric future. Most of this investment is in the distribution network, as shown below in Figure 18.

Figure 18 – Transmission and distribution investment by design and construction timelines. Source: EECA[39]



[39] The classification of connection complexity as 'minor', 'moderate' and 'major' adopted the following definitions: *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 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.

For process heat users to execute decisions as suggested by the MAC Optimal pathway, 85% of the transmission and distribution investment would be required within the next three years.

This is likely to be possible for the more straightforward investments (exclusively in the distribution network). However, transmission and the larger, more complex distribution investments have significant lead times. Our analysis estimates that around 63% of the transmission and distribution investment required for the MAC Optimal pathway will require lead times of between 2-4 years (six site connections out of 36 projects than needed some form of transmission connection investment) to design and construct these connections (including sourcing the equipment). These timeframes do not allow for any required regulatory consultation and approval process or obtaining the consents and property rights to enable the works. Our analysis did not consider the extra time required, but it appears that network investment may be a limiting factor for a number of the electrification decisions desired by process heat users.

This reinforces the need for process heat users and network companies to engage early and often, in order to minimise any delays in process heat users being able to execute their electrification plans. This engagement is critical to helping EDBs keep their asset investment and management plans up to date with the intentions of process heat users. For those EDBs subject to price-quality regulation, these plans are central to achieving the correct level of regulated revenue in each of the five-year regulatory control periods.

Implications of using flexibility to reduce investment

Process heat flexibility can improve system resilience and reduce both electricity system costs and process heat electricity-related costs.

As outlined above, our estimates of required transmission and distribution investment did not allow for demand flexibility to be used by process heat users. From a system perspective, if 20% of the MAC Optimal peak electricity demand (500MW) was able to be shifted away from periods when the overall electricity system is at or near its peak[40], it would reduce the need for the electricity system to provide peaking generation or storage by 100MW. As discussed above, a grid-scale battery of this size currently costs around $180M, while an equivalent gas-fired 'peaker'[41] plant of this size typically costs approximately $150M, plus the cost of natural gas to operate during peak periods.

Not only does flexibility in process heat demand reduce the need for expensive peaking generation and storage, the ability for process heat to be able to respond to system and network conditions (when system asset failures occur) increases resilience. The technology and communications systems are commercially available to allow this instantaneous response, where the underlying heat process allows.

40 As discussed above, typically cold winter weekday mornings and evenings.

41 I.e. open-cycle gas turbine.

By enabling flexibility in their process heat demands, process heat users could reduce their electricity procurement costs by up to $98,000 per MW of flexibility deployed every year.

In addition to benefits to the overall costs in the electricity system, process heat users can also financially benefit from using flexibility[42]. The regional RETA analyses highlighted how the use of flexibility in the process heat user's electricity demand – e.g. by changing its electricity consumption profile over the day – can help reduce or avoid electricity charges targeted at peak network or system periods. Our regional analysis allows us to estimate the potential value of three elements of the flexibility 'value stack':

Energy arbitrage: Retail electricity charges are likely to be higher during 'peak' periods – mornings and evenings during business days – than off-peak periods. Shifting some electricity consumption from peak to off-peak periods would reduce the total retail charges faced by the process heat user[43].

Network pricing arbitrage: Charges for the use of the existing transmission and distribution network ranged across the South Island, depending on the network and the size of the process heat demand. Typically, a significant component of these charges related to what the process heat user was demanding at peak network times[44].

Connection pricing: Finally, as discussed above, for most process heat users who converted to electricity, some degree of investment would be required to increase the capacity of the network. For smaller sites, or sites connecting to networks with sufficient pre-existing capacity, the amount of network investment was relatively modest. However, some required moderate or major investment in the distribution network. For sites that could smooth their consumption profile, or invest in onsite batteries, the quantum of investment required could potentially be reduced[45].

42 In fact, this is inherent in the design of the market – the financial benefits to the system, from flexibility, will be shared with the organisations that are providing the flexibility when the underlying retail and network prices are an efficient reflection of market prices. However, today, New Zealand is at an early stage in developing the market systems that allow electricity consumers to participate in the 'flexibility' market. This discussion here focuses on financial benefits that process heat users should be able to access today, noting that New Zealand will continue to make progress in this regard. See https://flexforum.nz.

43 Using the retail price forecasts EECA procured for the RETA workstream, the 'energy' component of retail electricity charges during weekday days is expected to average 16c/kWh between now and 2030, while weekday nights are expected to average 11c/kWh. Businesses that can shifting 1MWh of consumption from day to night, every weekday, would save the process heat user $10,000 per annum.

44 The published tariffs from South Island EDBs varied significantly in what variables they used to determine network charges. These included daily fixed charges, time-of-use c/kWh charges, anytime maximum demand charges, congestion period demand charges and connection capacity charges. It is challenging to make a definitive assessment of how much of these charges could be avoided by deploying flexibility. Our analysis below conservatively assumes only 50% of the overall charges could be avoided.

45 Our analysis of each of these sites suggests the average construction cost of these investments was $878,000/MW.However we also assumed that the capital contribution by the process heat user would be 50%.

Figure 19 – Estimates of the value of flexibility in South Island RETA. Source: EECA[46]

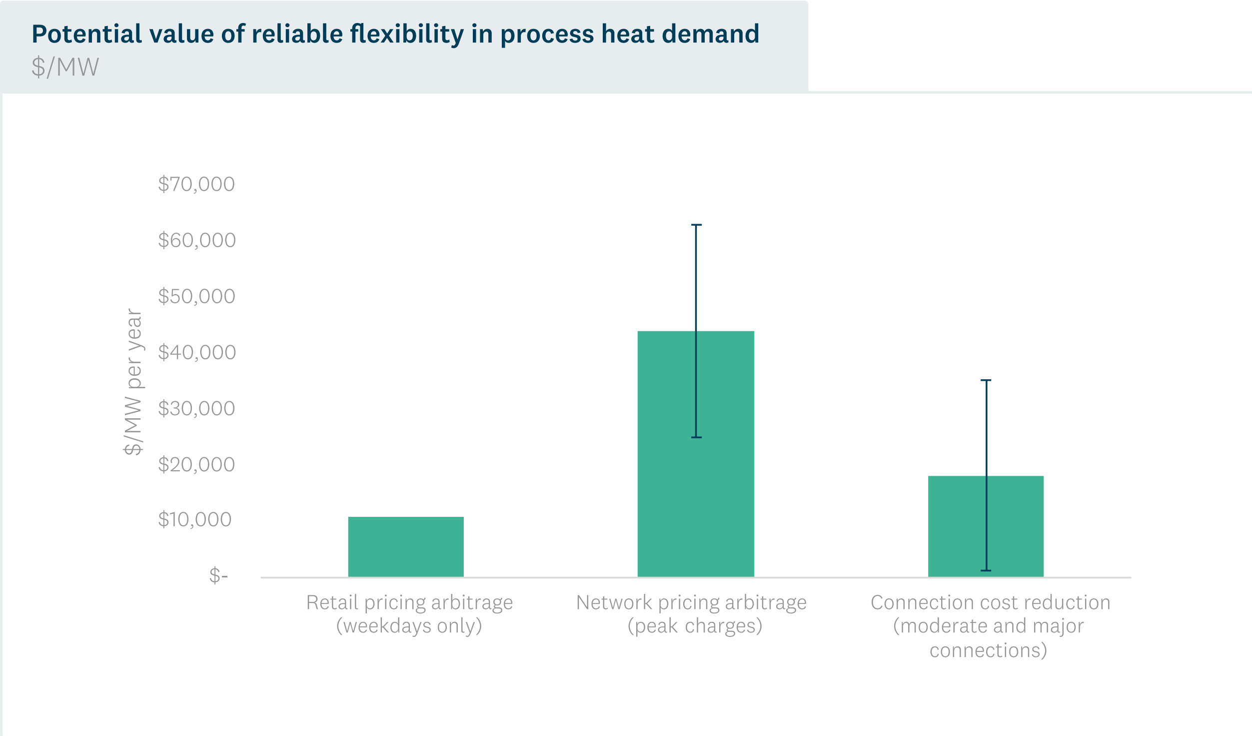


Figure 19 uses plausible estimates from the RETA analysis of what this flexibility could be worth to a process heat user, per MW of demand that can be shifted into an off-peak period. We note that, in reality, the estimate for reducing connection costs may vary significantly, as the underlying equipment underpinning network investment comes in standard sizes – varying peak process heat demand by a relatively small amount may not change the connection costs. The error bars in Figure 18 indicate the 10th and 90th percentile values calculated across the different regions. However, depending on which network they are connected to, a process heat user that has sufficient flexibility in their underlying process could obtain between $37,000 and $63,000 per year for every MW of flexibility it routinely uses to avoid peak retail and distribution network charges, and, additionally, up to $35,000 (annualised) if it allows them to reduce the size of their connection to the network.

Some process heat users may find it challenging to alter their underlying process to achieve this. Even then, onsite batteries could be used to extract these cost savings. Over a 20-year timeframe, the cost savings above could be sufficient to underwrite an investment in a battery. Onsite battery storage also provides extra resilience in network failure scenarios. EECA is working with process heat users to better understand the value streams associated with batteries that are integrated into their electrification plans.

46 In all likelihood, the benefit of reducing the connection cost will be experienced as an up-front financial benefit. However, we have converted this to an annuity to allow a better comparison with the other annualised revenue streams.

6.3 Implications for the biomass market

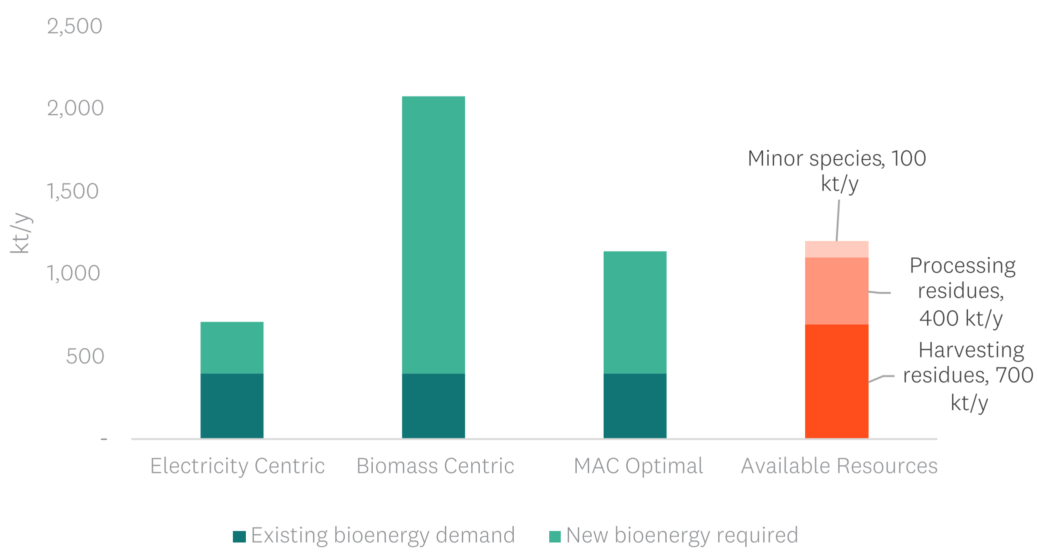
Across the period 2024-2037, the MAC Optimal pathway would create new demand for nearly 8M tonnes of woody biomass. This would more than double the existing use of bioenergy in the South Island.

Biomass for new process heat demand was only considered if it was not currently utilised or contracted to an existing market. Generally, this meant that only harvesting and processing residues were considered (after subtracting off existing bioenergy or wood product demand). When this was insufficient, the cost implications of diverting lower grade export wood (KI, KIS) were considered.

Figure 20 shows biomass demand in 2037 in the different pathways, and compares these with the available, and currently unutilised, woody biomass resources.

Figure 20 – Growth in biomass demand under MAC Optimal and Biomass Centric[47] pathways. Source: EECA

Biomass volumes required to meet existing and new bioenergy demand
kt/year, 55% moisture content



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

Treating the entire South Island as one 'market', available and unutilised sources of woody biomass is sufficient to deliver an Electricity Centric and MAC Optimal future (assuming a moisture content of 55%), but not a Biomass Centric future. In a Biomass Centric future, demand for biomass would exceed residues and minor species by around 800kt per year, by 2037, when coal boilers for low-to-medium temperature (delivered heat under 300°C) process heat are prohibited. These resources would have to be supplemented by, for example, diverting lower grade Export KI and KIS specification logs from their export markets.

However, the availability of these biomass resources through time fundamentally relies on the harvesting activity of forest owners. We based our analysis around MPI's Wood Availability Forecast, which described the total potential woody biomass in the region (Figure 21).

Figure 21 – Wood Availability Forecast for the South Island, 2023-2050. Source: EECA

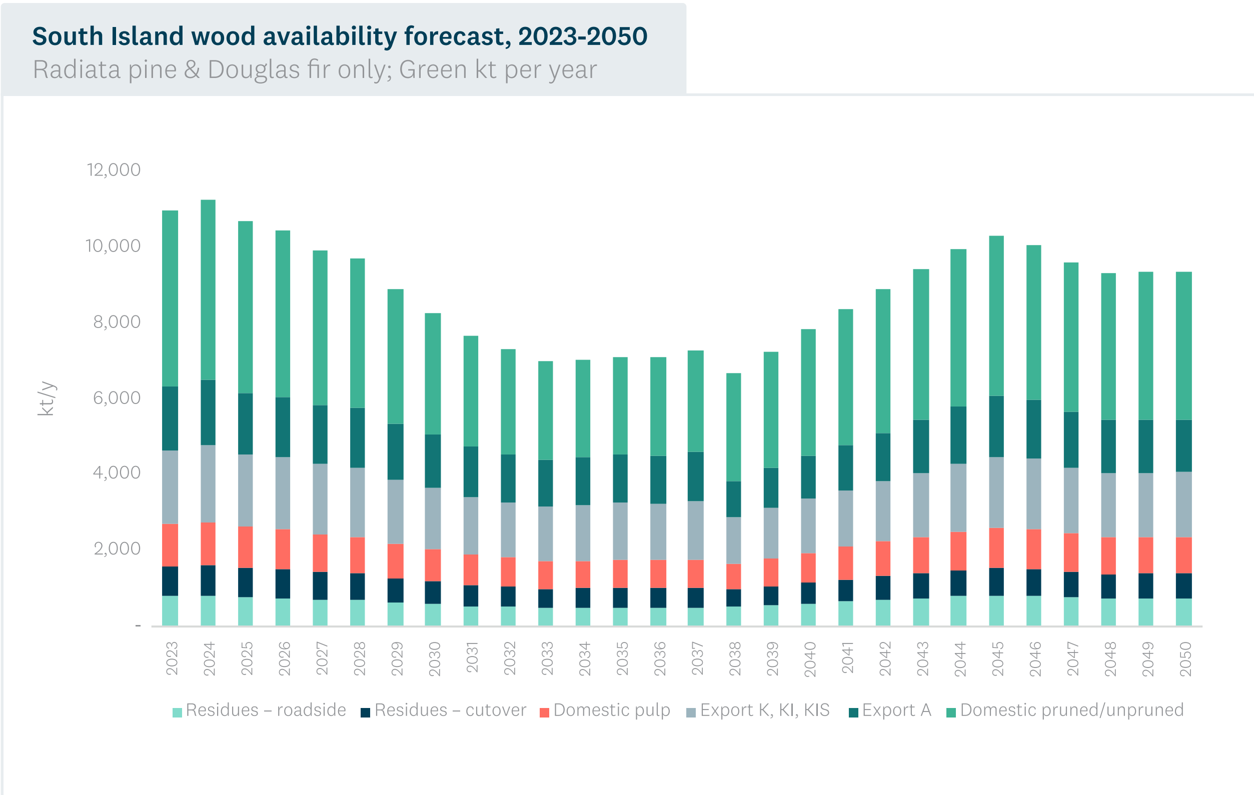


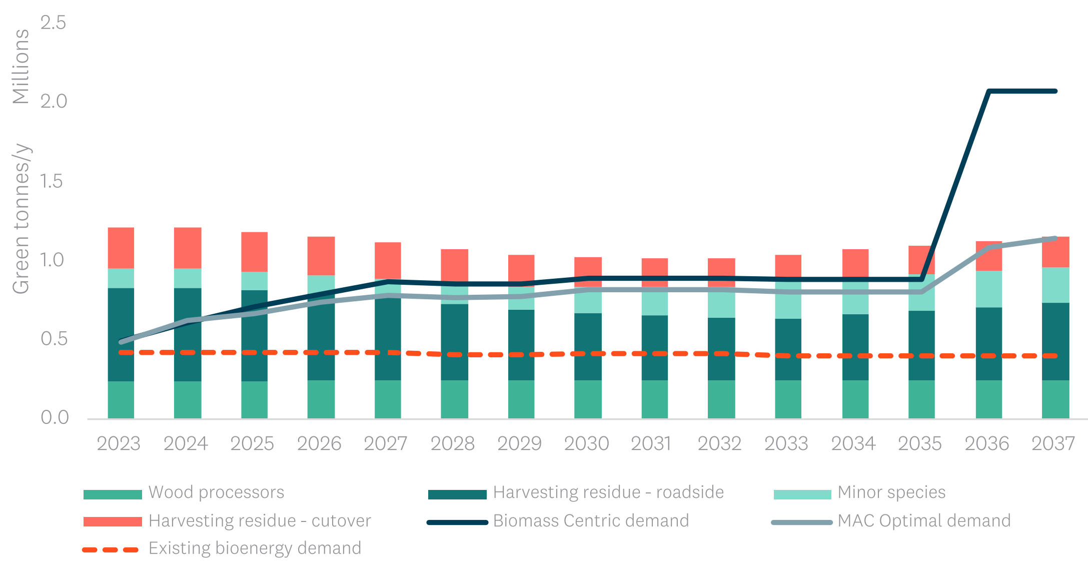
Figure 21 shows that – based on the WAF's modelling of forest owners harvesting intentions – the availability of wood varies significantly through time. Depending on log prices, forest owners harvesting activity may vary from the WAF by a small number of years, but the general shape of Figure 21 is unlikely to materially change.

By 2027, the MAC Optimal pathway would fully utilise all recoverable roadside residues in the South Island. By 2036 it would have used almost all available and unutilised resources identified in the regional analyses.

To understand the implications for demand for process heat bioenergy through time, Figure 22 overlays the MAC Optimal and Biomass Centric biomass demand (including existing bioenergy demand) on the available resources. It can be seen that in the MAC Optimal pathway, the combination of existing and new process heat related demand is utilising most of the available resources after 2026, with minor species[48] and economically recoverable residues[49] being the 'marginal fuels' for these years. As indicated above in Figure 20, by 2037, the Biomass Centric demand has outstripped these available resources.

Figure 22 – Annual South Island biomass supply and demand balance, 2023-2037. Source: EECA

South Island available biomass supply vs RETA demand
Green tonnes per year



The cost of harvesting, collecting, and storing the available and unutilised biomass[50] needed for the MAC optimal pathway could be between $525M to $604M.

48 The major species focused on in the NEFD are radiata pine and Douglas fir. Other species (e.g. eucalyptus) are grouped together as 'minor species'.

49 The most challenging aspect of assessing the availability of harvesting residues for bioenergy is the practicalities of recovering them. While 'roadside' residues are usually found near roading access at skid sites, residues left in the cutover are more difficult to recover, often in steep terrain. Geospatial analysis of the terrain undertaken by Ahikā and Margules Groome for EECA suggested that, on average, 75% of roadside residues and 25% of cutover residues were economically recoverable.

50 Before processing into more usable forms such as dried woodchip and pellets.

Together with Figure 8, we can see that between 2026 and 2037, the marginal cost of biomass (at a centralised hub, but prior to processing) will be between $92/t and $106/t ($14-15/GJ[51]), in real terms. The implications for the biomass market in the South Island could be significant:

Across the period 2024-2037, new demand for nearly 5.7M tonnes of woody biomass would be consumed in the MAC Optimal pathway. Using the cost figures above as a proxy for the value of biomass for bioenergy, the total potential value of the process heat biomass market in the South Island, over the 2024-2037 period, could be between $525M to $604M.

For large users, some additional processing costs will be incurred in processing the woody biomass into dried woodchip (typically at a moisture content of ~30%). We estimate the final delivered price for dried wood chip at approximately $25/GJ (or $316/t[52]), with a total of 5,000TJ of annual energy demand from these large users.

For smaller consumers, wood pellets are likely to be preferred due to convenience. Manufacturing wood pellets incurs higher processing costs than woodchip, raising the estimated price to the final user to $28/GJ ($490/t[53]), with a total of 351TJ of annual demand from these smaller users.

Figure 23 shows the delivered bioenergy costs for different sizes of process heat users.

Figure 23 – Estimated costs of bioenergy for different sizes of RETA sites. Source: EECA

51 Real figures.

52 Dried woodchip is assumed to have a calorific value of 12.6GJ/tonne.

53 Pellets are assumed to have a calorific value of 17.5GJ/tonne.

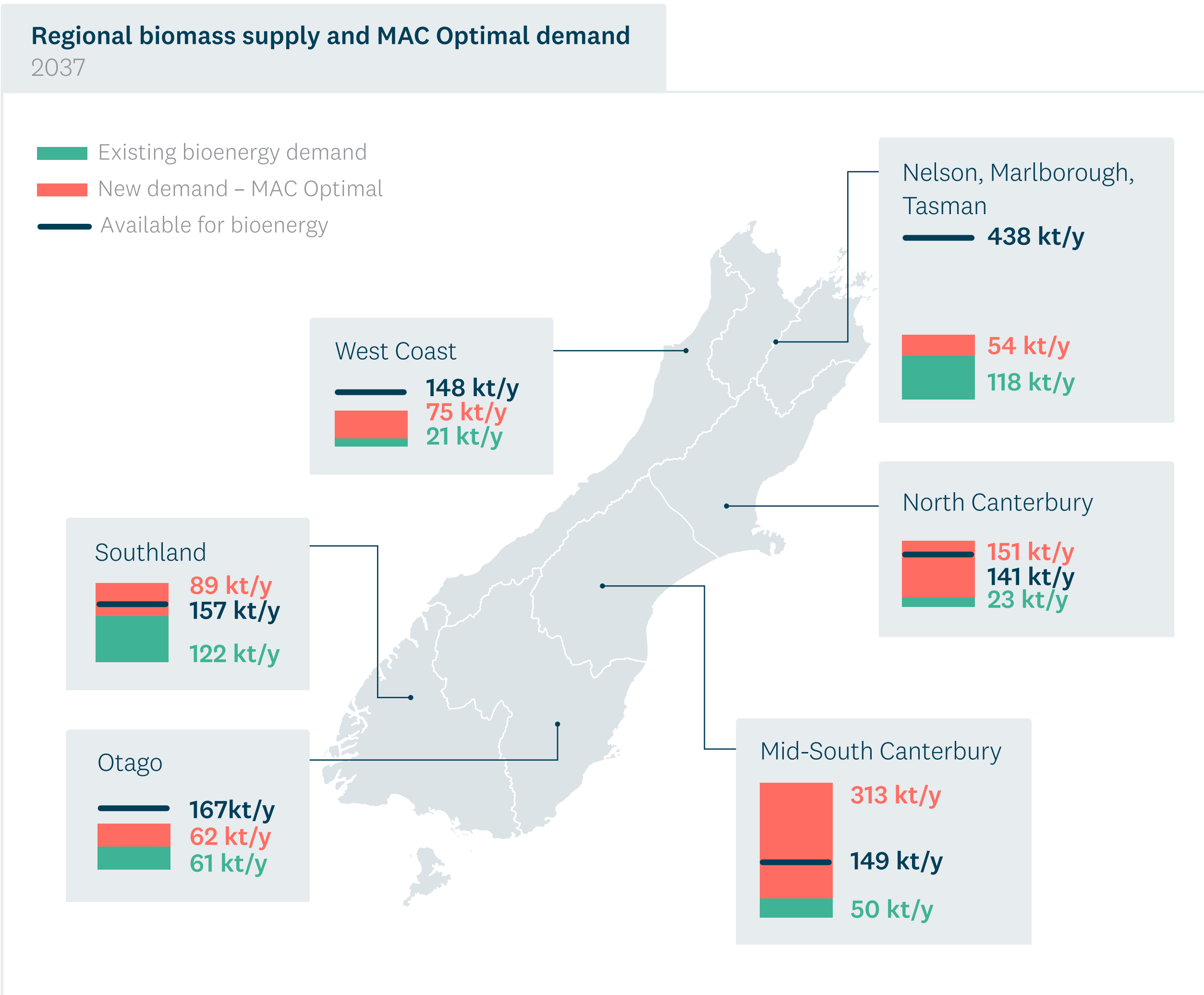
Potential for inter-regional trade in biomass

There is an opportunity for inter-regional trade in the South Island, but the cost of trucking makes it challenging for Nelson Marlborough Tasman to export its significant surplus.

And finally, these sources of bioenergy will incur delivery costs from the processing 'hub' to the process heat user.

In determining final bioenergy price, our individual regional analyses assumed that all biomass fibre was sourced, processed, and delivered within the region. Some regions had insufficient residues and minor species to meet the MAC Optimal demand (including existing demand), whilst others – particularly Nelson Marlborough Tasman – had a surplus (Figure 24). In the regions that had shortfalls, the regional analyses assumed that lower grade export logs would be diverted from their export destination to meet this local demand, at a cost commensurate with the export price forgone. Figure 24 illustrates that, despite this, biomass was the lowest cost fuel for a sufficient number of projects to require procurement of export-diverted logs.

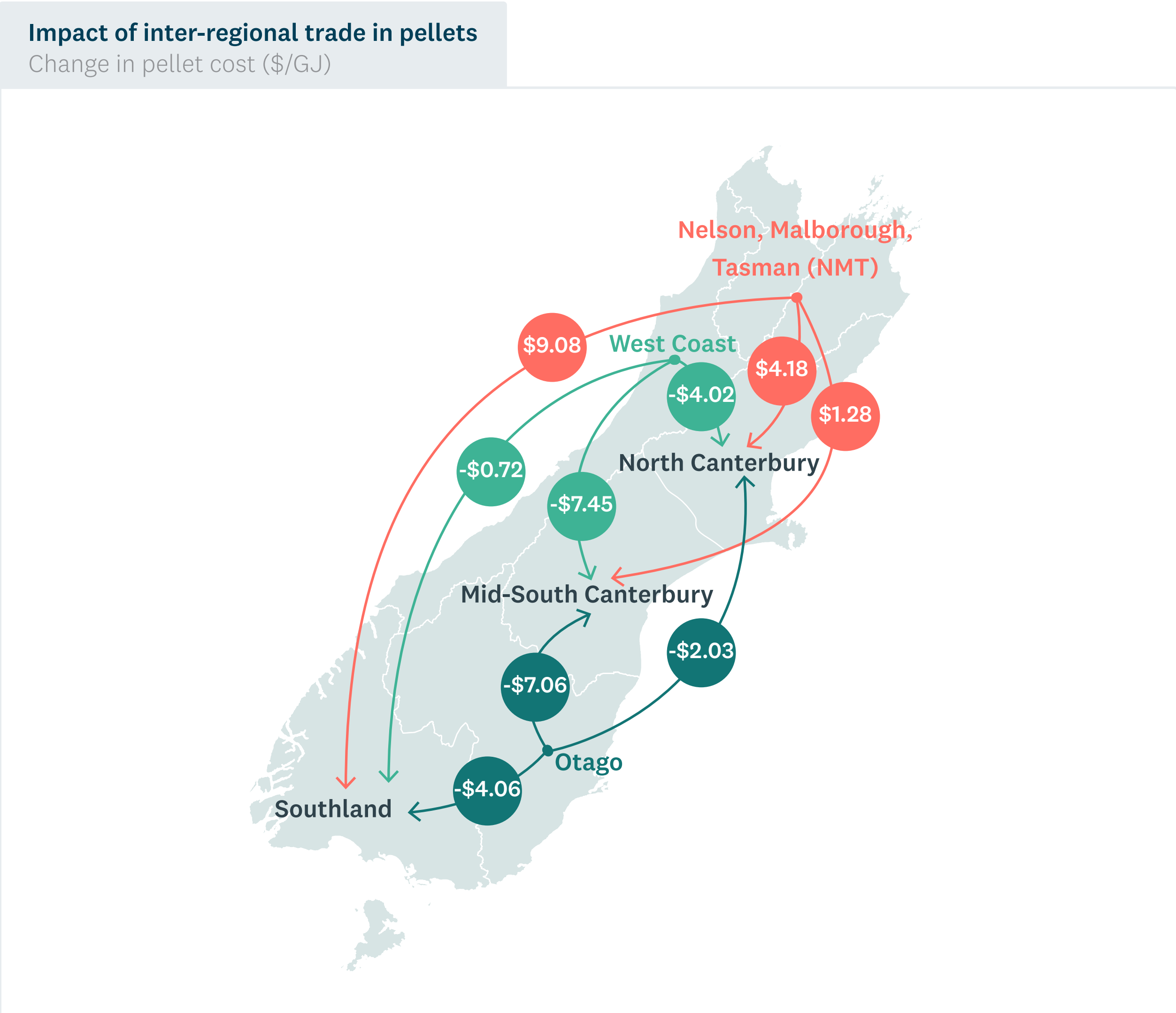
Figure 24 – Biomass supply-demand balance in individual South Island regions. Source: EECA



The more complete South Island picture in Figure 24 shows that there is an opportunity for inter-regional trade within the island. However, the ability to move biomass between the regions must take into account the mode and cost of transport. While a small amount of the surplus from Nelson Marlborough Tasman and the West Coast could be shared with the Canterbury region[54], the area with the largest shortfall is Mid-South Canterbury[55], which is around 550km by road from Nelson and 350km from Greymouth.

Each of the six South Island regional workstreams determined the local cost of biomass assuming it was all procured from local forestry and processor resources. Typically, regions with a surplus of biomass had lower costs. To illustrate the impact of inter-regional trade, we have added transport costs to the local cost of biomass in those regions with a surplus. This analysis assumes that pellets are transported by road, in 30 tonne trucks consuming diesel. The cost associated with transporting wood pellets from the three regions in surplus, to the three regions with insufficient available resources, is shown in Figure 25.

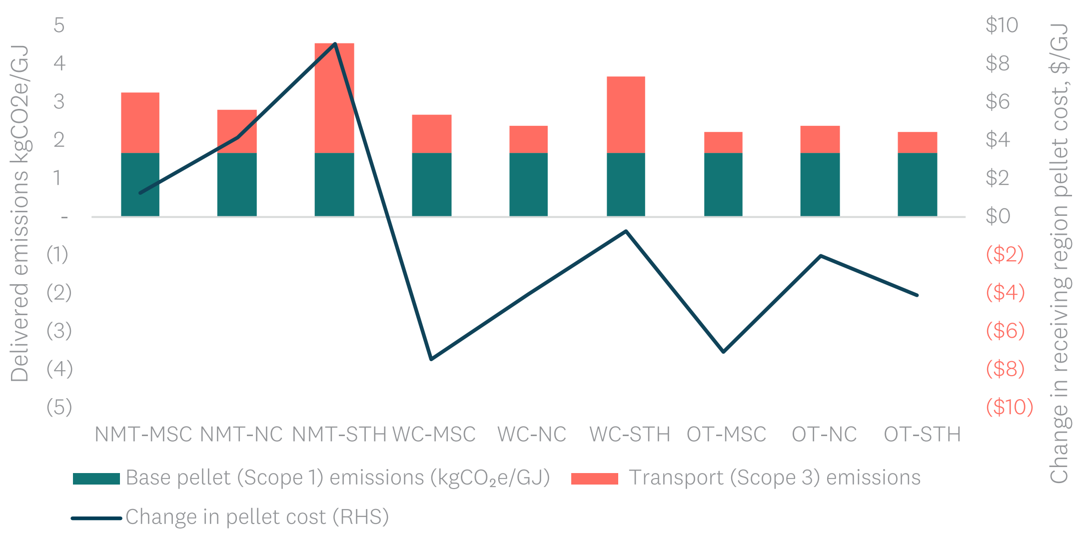
Figure 25 – Change in cost of wood pellets and biomass emissions from inter-regional trade. Source: EECA



[54] 400km between Nelson and Christchurch, and 550km between Nelson and Timaru.

[55] A number of large forestry blocks, and biomass consumers, were near the border between Otago and South Canterbury. Therefore the stark difference in the supply-demand balance here may partly be an aretfact of where these boundaries are. However, Fonterra's announcement to switch to biomass for two boilers at Clandeboye is a significant part of the undersupply in South Canterbury.

Impact of inter-regional trade in pellets
Change in pellet cost ($/GJ) and emissions (kg CO_2e/GJ)



Trucking the wood from Nelson Marlborough Tasman to any of the regions with a deficit of unutilised biomass would lead to higher cost pellets that the current alternative for those regions (diversion of low-grade export logs). However, both the West Coast and Otago could plausibly export to any of the deficit regions and still provide lower-cost pellets than assumed in the regional analysis. This would result in a change in MACs for sites considering biomass, and potentially change their fuel switching decision[56].

Inter-regional transport of wood pellets creates Scope 3 emissions, which would increase the effective emissions of biomass by between 34% and 170%.

Transporting pellets beyond the three surplus regions increases the scope 3 emissions associated with choosing bioenergy, proportional to the distance driven. In three cases (exporting from Nelson Marlborough Tasman to South Canterbury or Southland, and exporting from the West Coast to Southland), it more than doubles the effective emissions intensity of bioenergy.

That said, even in the case of trucking pellets from Nelson-Marlborough to Southland (~1,000km), the emissions intensity of biomass still only reached 4.5kg CO_2e/GJ; 5% of the emissions factor of coal and 7% of the emissions factor of LPG.

However, there are wider impacts to transporting pellets by road than just cost and emissions. If 20% of the MAC Optimal biomass demand in Canterbury and Southland was met through imported pellets, it would result in an additional 1,536 30-tonne truck movements every year. Assessing the impact on South Island roads is beyond our scope.

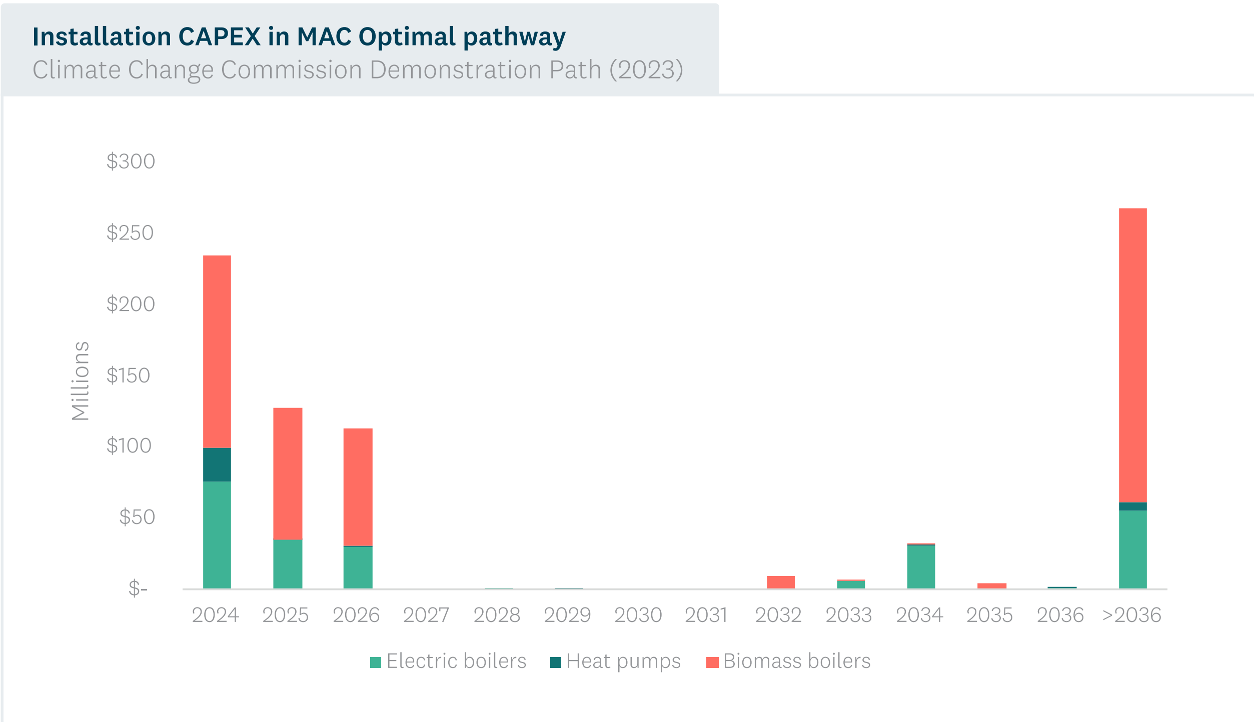
[56] We performed an indicative analysis for sites in both North and South Canterbury importing from the West Coast; the reduced cost of pellets was not sufficent to change any site's decision from electricity back to biomass.

6.4 Implications for supply chains

Including their estimated contributions to electricity network upgrades, South Island process heat users will spend nearly $1B on installing heat pumps, electrode boilers and biomass boilers over the next 15 years.

Using estimated installation costs, Figure 26 shows the CAPEX implications of the MAC Optimal pathway for process heat users between 2024 and 2037. The analysis described earlier in the report sees a substantial amount of investment – between $100M and $250M per year – occurring over the next three years. Around $250M of investment wouldn't be triggered until the NPS on process heat requires the end of burning coal for process heat.

Figure 26 – Estimated annual capital expenditure for installing heat pumps, electrode boilers and biomass boilers. Source: EECA



Of course, in addition, process heat users switching to electricity may have to make capital contributions to network upgrades. Overall, this would result in:

41 Electrode boiler installations

94 Heat pump installations

127 Biomass boiler installations

24 Distribution network upgrade projects

6 Transmission network upgrade projects.

In the MAC Optimal pathway, over half of these projects occur in the next three years.

As we have outlined above, there are a range of factors that will dictate the actual timing of process heat users switching fuels:

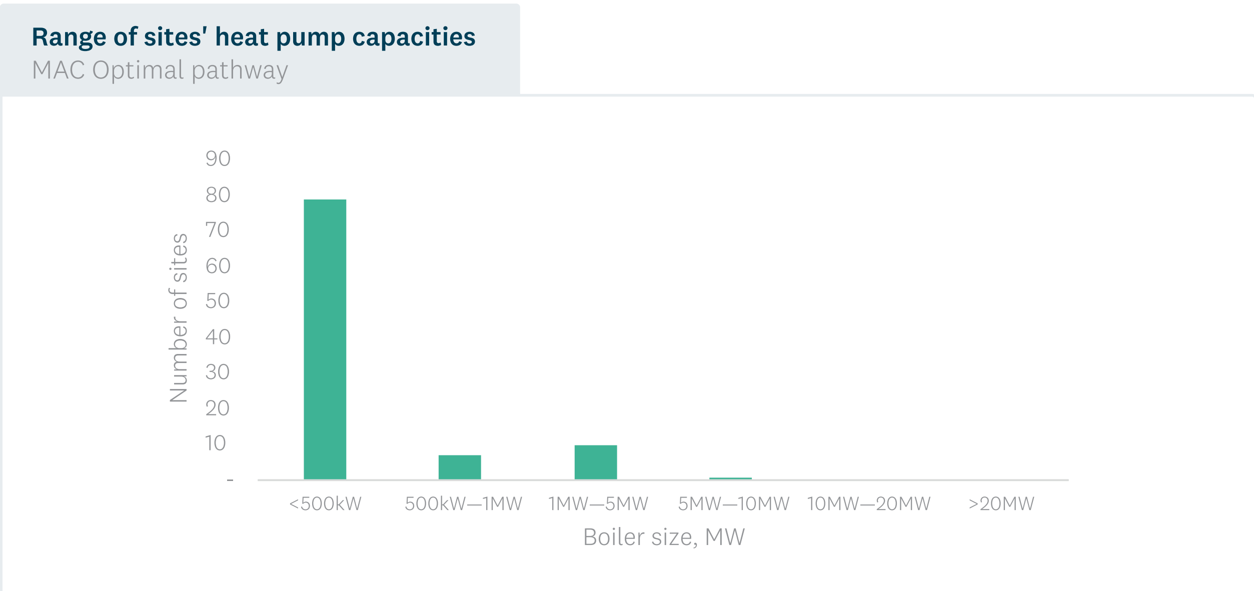
- The CAPEX timings in Figure 26 are based on estimates of a range of financial variables faced by process heat users, which will be refined by those users as they engage with Transpower, EDBs, electricity retailers, biomass providers and equipment suppliers.
- The timings are also based on the CCC's Demonstration Path. Individual process heat users are likely to form their own expectations of the future carbon price.
- Any project requiring network upgrades may face delays as they await the completion of these upgrades.
- Factors that we have not been able to model, such as process heat users' access to (and cost of) capital, and wider market and strategic considerations.

Therefore Figure 26 is unlikely to accurately predict the actual pace of development. But it does highlight the sheer number of projects that – at least based on a screening analysis – will likely be economic at some point in the next 5-7 years. This warrants a serious consideration of the ability of supply chains, and the workforce, to deliver the requirements of process heat users.

A recent analysis by DETA for the CCC suggested that process heat decarbonisation, nationally, will result in $3.5B of equipment being purchased and installed, and a need for an additional 8,600 personnel across a variety of skillsets, between now and 2037. If that is taken as an approximate guide, the CAPEX identified in the South Island RETA by itself would create around a quarter of this workforce requirement – an additional ~2,200 personnel. These people need to be trained, qualified and mobilised.

There are opportunities as well. Of the 94 heat pump installations required by the MAC Optimal pathway, 80 of them are <500kW in size. This size and quantity creates an opportunity for local heat pump component manufacturing and assembly.

Figure 27 – Range of heat pump sizes required in the MAC Optimal pathway. Source: EECA



7 Recommendations and opportunities

This report has generated a range of new insights into the opportunities and implications of process heat decarbonisation, based on our experience in the South Island. We now have a much more sophisticated understanding of what process heat decarbonisation means for:

- **Process heat users** as they consider the financial case for eliminating their use of fossil fuels, including the practical implications for establishing supply arrangements for low emissions alternative fuels
- **Foresters and bioenergy suppliers**, as they consider the potential value to process heat users of currently unutilised and available woody biomass, and the logistics and business opportunities available in collecting, chipping, storing, and processing these residues into products for process heat users
- **Electricity generation investors** as they build their expectations of electricity demand growth (consumption and peak demand) over the coming years
- **Electricity retailers and flexibility coordinators** as they develop products and services that will make it easy for process heat users to minimise their capital and operating costs from choosing electricity as a low emissions fuel, including the deployment of flexibility where possible, and
- **Electricity transmission and distribution network owners** as they plan their network investments, efficiently accommodate the needs of process heat users, and resource themselves accordingly.

Each regional report contained a range of recommendations and opportunities for that region. Below we outline a set of recommendations and opportunities that we believe are critical to enabling the accelerated path illustrated by our MAC Optimal pathway which, as outlined above, would reduce the cumulative release of long-lived emissions by 6.2Mt over the period of the RETA analysis to 2037, compared to a 'business as usual' pathway.

The Forest Owners Association could lead the development of an 'energy grade' to increase the understanding of the costs of recovering harvesting residues, drive more efficiency into collection of residues and thus assist in the development of bioenergy markets.

The cost of recovering harvesting residues is the most challenging to estimate. Current log grades are defined around their suitability for an end use timber product, rather than their suitability for bioenergy. Markets for residues are still in their infancy, and residues are often perceived as low or zero value. Without a clear market value, there are no standardised approaches to understanding how much forest owners should pay for residue collection.

The cost of recovering harvesting residues is the most challenging to estimate. Current log grades are defined around their suitability for an end use timber product, rather than their suitability for bioenergy. Markets for residues are still in their infancy, and residues are often perceived as low or zero value. Without a clear market value, there are no standardised approaches to understanding how much forest owners should pay for residue collection.

However, there is a range of woody biomass in the forest which, if destined for bioenergy, would require less handling, cutting and in-forest infrastructure than current log grades. Our proposal[57] is to develop an 'energy-grade' that reduces waste, improves harvesting efficiencies, lowers transportation costs, and provides for a cleaner fibre. That said, the specification of an E-grade log can be broad – limited only by the safe transportation and the dimension limitations of any wood chipping facility. In essence, if it can be picked up, chipped, and burned (or pelletised), then it is viable.

The development of an E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the 'integrated model' of cost recovery, outlined above, achieve the best outcomes in terms of recovery cost and volumes.

Explore opportunities to enhance wood pellet manufacturing near major biomass resources.

The analysis above has highlighted the potential new demand for both wood pellets (for biomass boilers) and heat pumps.

Our regional analysis assumed that only small users (boilers <1MW in size) would prefer wood pellets, primarily due to the handling and storage requirements associated with other forms of biomass (e.g. hogfuel and woodchip). Using this assumption, small users consume 20,000t ($10M) of pellets every year in our MAC Optimal pathway by 2037.

The potential for pellets extends beyond small users, however. Larger industrial users are expressing an interest in pellets. Generally existing coal boilers will need to be modified to use dried woodchip as a fuel. Pellets are ~10% more expensive (in our modelling), but require fewer modifications, and can be stored more easily. That said, the higher pellet price may mean that electricity becomes the preferred fuel.

We are also aware of investigations into manufacturing black pellets in New Zealand, which also avoid some or all of the modifications required to existing coal boilers. However, the same commercial logic applies – black pellets (as well as white pellets) need to be cost competitive with a fuel switch to electricity to be a superior option.

Overall, the new demand from small users of 20kt/year, as well as the potential for demand from larger users, could be enough to underpin the establishment of additional pellet manufacturing capability. Research by Indufor (2021)[58] suggests even small pellet mills (up to 70kt/year), requiring modest investment of around $44M, would have reasonable payback periods. Our analysis in Section 6.3 suggests it might be sensible to locate such a plant in the West Coast or Otago, enabling the transport of pellets from biomass-rich regions to Southland and Canterbury.

57 Our proposal was originally initiated by Margules Groome.

58 Indufor (2021), NZ Wood Fibre Futures Project Stage Two, Final report for Te Uru Rākau.

Explore the opportunity to establish a local heat-pump assembly and/or component manufacturing plant.

The MAC Optimal pathway suggested that, over the period 2024-2037, there would be demand for nearly 100 heat pumps. Eighty of these were under 500kW, and half of those would be 'optimal' in the next 2-3 years. We suspect that RETA projects in the North Island will yield an even larger demand than the South Island.

We are not aware of any investigation into establishing local heat pump component manufacturing or assembly capability at a scale and global cost-competitiveness that is appropriate for New Zealand. However, international supply chains for heat pump equipment may not be able to meet this demand, in which case there may be reason to establish a local capability of some degree.

Electricity distribution businesses should provide standardised 'connection feasibility information templates' to improve the efficiency of information sharing with process heat users.

EDBs (and Transpower) are facing an unprecedented level of enquires about connecting to their network. However, existing EDB processes are not designed to cater to this volume of demand, or the uncertainty that connecting parties face in terms of their desired connection size. This is particularly true early in the 'customer journey' of a process heat user when they are still developing their options for decarbonisation. If EDBs do not stay abreast of their evolving thinking, the connection process can become difficult. A much more engaged and dynamic communications approach is required.

Electricity industry efforts are beginning to develop improved connection processes. Both the Electricity Authority's Network Connections Technical Group, and Electricity Network Aotearoa's 'Future Networks Forum' Connections workstream, are pursuing improvements in this critical area. Our regional reports recommended that EDBs and process heat users engage early to allow the EDB to develop options for:

- How the process heat user's new demand can be accommodated
- What the capital contributions and associated lines charges are for the process heat user, and
- Any role for flexibility in the process heat user's demand.

This allows both EDBs and process heat user to find the overall best investment option.

The regulatory and ENA workstreams underway should collaborate with process heat users and EECA around the development of a 'connection feasibility information template' as an early step in the connection process. This template would include a section for process heat users to provide key information to EDBs, and a network section where EDBs provide high-level options for the connection of the process heat user's new demand. Information provided by EDBs would include the potential implications of each option for construction lead times, capital contributions, network tariffs and the use of the customer's flexibility.

EDBs should make capital contributions and network pricing policies and methodologies easier to understand and easier for process heat users to estimate the financial impact on electrification business cases.

Process heat users (especially smaller sites) would benefit from improved network data and plain-English guides to EDB pricing methodologies and capital contributions policies. This would allow process heat users to undertake their own discovery of estimated pricing and network capacity information efficiently, rather than having to do this bilaterally with the EDB.

EECA appreciates the Electricity Authority's establishment of the Network Connections Technical Group to address some of these issues, but notes that its scope does not include pricing. Pricing information is critical to process heat users at the early stage of optioneering, and we ask that the Authority seek improved clarity and consistency among EDB policies and methodologies.

EDBs should improve their network pricing signals for flexibility based on the value to the network.

In Section 6.2 we provided an indicative assessment of the value that could be available to process heat users from enabling flexibility in their heat plant. Equally, this flexibility could be provided by an onsite battery.

However, each site has its own characteristics – both in terms of the flexibility actions it could enable, but also the potential areas in which it could reduce capital and operating costs. The 'value streams' that would accrue to this flexibility are a function of the retail tariff and network pricing[59]. For commercial loads, 'time of use' tariffs are widely available, but more advanced and dynamic arrangements are still emerging. Further, the Electricity Authority recently noted that one of the slowest areas of development of network pricing was tariffs that rewarded flexibility[60]. We ask retailers and flexibility aggregators to continue to evolve tariffs that reward flexibility based on wholesale market signals and, where relevant, network signals as well.

We also ask EDBs to improve their commercial arrangements for rewarding flexibility, and for the Authority to act decisively where progress is not forthcoming.

EECA should work with retailers, distributors, and flexibility aggregators to make it easy for process heat users to discover, evaluate and enable flexibility where it can reduce their capital and operating costs of electrification.

Today, most commercial and industrial retail electricity pricing arrangements have incentives for process heat users to shift their electricity demand from high-priced periods to low price periods. As highlighted above, across the South Island there are a spectrum of approaches to distribution pricing, some of which incentivise process heat users to reduce demand at peak network times.

However, these simplistic arrangements, in and of themselves, do not make it easy for process heat users to discover the different options for making their process heat flexible, or evaluate the long-term 'size of the prize' from investing in systems that automate and optimise their response.

59 Both connection cost and ongoing network pricing.

60 'There has been little progress in establishing price signals that reward flexibility and some regression with respect to services subject to control', page 3, 'Targeted reform of distribution pricing', Electricity Authority, 2023.

Here, case studies of process heat users reducing their electricity procurement costs by enabling flexibility are useful tools in raising awareness and understanding of the incentives, systems and capabilities required to do this well. Given the spectrum of process heat businesses involved in the South Island RETA, case studies will need to cater for a variety of settings. There is an obvious role for EECA in providing case studies, decision-support frameworks, and simple modelling tools to help process heat users enable and optimise their use of flexibility.

Objective scenario-based carbon price forecasts need to be developed so that decarbonising organisations can incorporate into their business cases. Ministries (such as Ministry for the Environment) need to facilitate appropriately qualified organisations to produce these.

Above we have argued that the decision about the timing of decarbonisation – and therefore the prospect for accelerated emissions reduction – is dependent on the expectations process heat users from about the future carbon price arising from the NZ ETS.

While we have used the CCC's demonstration path carbon prices to simulate decisions for the MAC Optimal pathway, the CCC's path is not a forecast. Process heat users would benefit from scenarios of carbon prices (based on different assumptions) when evaluating their decarbonisation decisions. However, unlike other input costs (e.g. electricity prices), future scenarios of carbon prices are very hard to procure.

Reputable organisations likely exist who could undertake this modelling. We recommend that Ministries (such as Ministry for the Environment) work with these organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.

EECA will expand the scope of future Regional Energy Transition Accelerators to include transport, for a more complete picture of a region's energy pathway. EECA should also make available models that stakeholders can use to explore pathways under different assumptions.

This first version of RETA focused on process heat only, for the reasons outlined in Section 4. While this allowed for a highly detailed view of potential decarbonisation investments, it did not paint a full picture of the impacts on the region's energy system from transport and process heat decarbonisation. Transport and process heat energy needs will have implications for both electricity and biomass. A future version of RETA must include transport.

Furthermore, the majority of the analysis conducted for the South Island RETA was only made available in the form of a report that was completed at a particular time. As indicated in this report, some underlying information was superseded as we progressed from region to region. This will inevitably continue to happen. Future RETAs will develop public-facing online pathway models, which will allow for the efficient updating of information, but also for users to input their own assumptions.

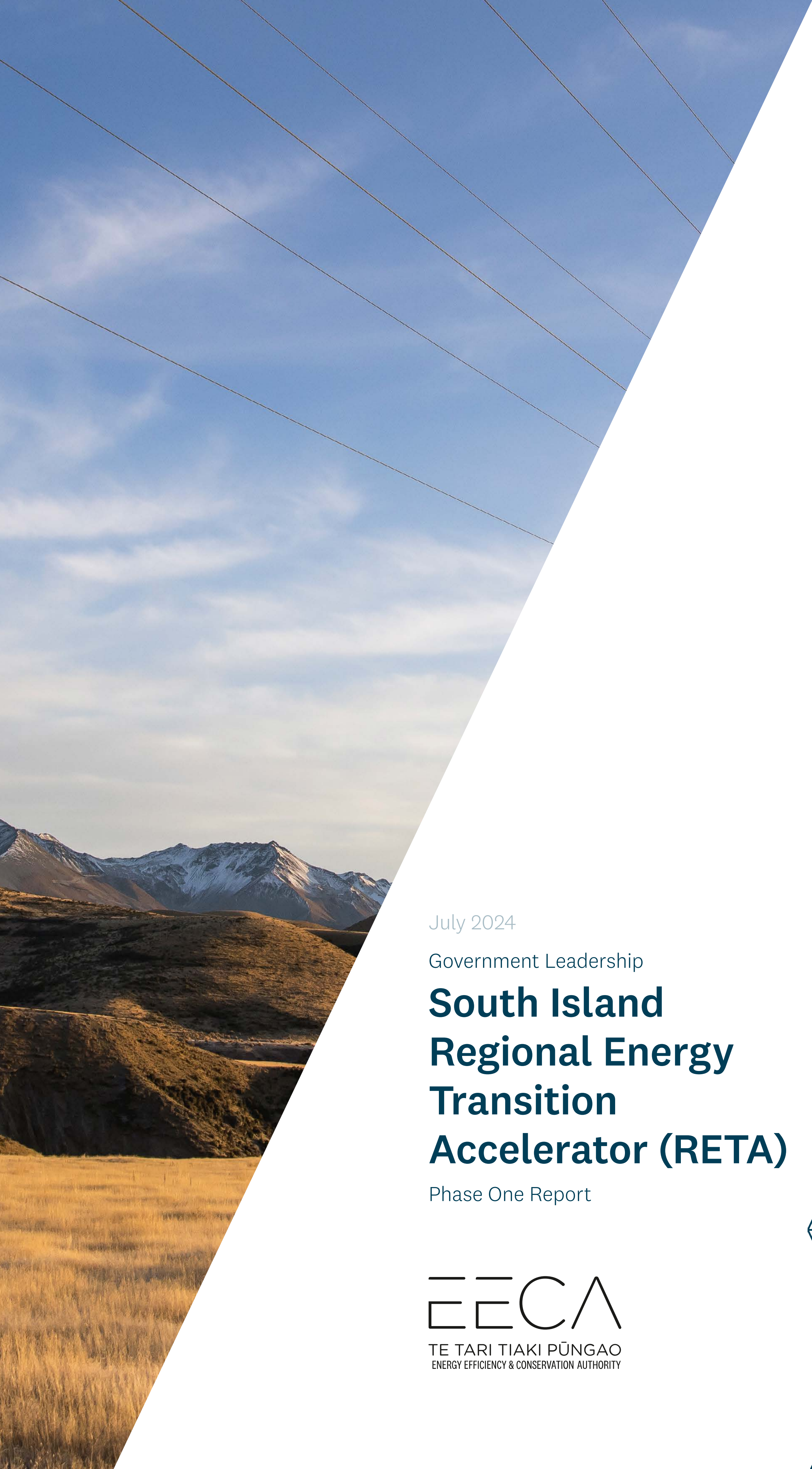
Power lines, Canterbury, New Zealand. Credit – Chris Stanley.

8 Appendix: South Island RETA participants

The six South Island RETA projects 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 the South Island
- Regional economic development agencies
- Local electricity distribution businesses
- National grid owner and operator Transpower
- Regional forestry companies
- Regional wood processors
- Electricity generators and retailers
- Demand side assessments and modelling: DETA, Lumen
- Biomass workstream advisors: Ahikā, Margules Groome, PF Olsen
- Electricity workstream advisors: Ergo
- Waste workstream advisors (Mid-south Canterbury only): Tonkin and Taylor
- Wayne Manor Advisory – report collation, publication, and modelling assistance.

Photo: Lake Grassmere, Marlborough, New Zealand. Credit – Dominion Salt



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Government Leadership

South Island Regional Energy Transition Accelerator (RETA)

Phase One Report

EECA
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