Government Leadership

Regional Energy Transition Accelerator (RETA)

Otago – Phase One Report

September 2023

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

1 Foreword

Energy efficiency and the uptake of renewables, by industry, will play an important part in achieving net-zero carbon emissions by 2050. Currently, around a third of New Zealand's overall energy use is creating heat for industrial processes – 60% of this energy currently sourced from fossil fuels.

Understanding unique region-specific needs, opportunities and barriers is critical. EECA's Otago Regional Energy Transition Accelerator (RETA) programme aims to develop and share a well-informed and coordinated approach to help fast-track regional decarbonisation. It provides a common set of information to industry considering emissions reduction and to energy suppliers who can support the transition to renewable energy underway in the region.

Our RETA work leverages the site-specific decarbonisation pathways developed for organisations across the region through EECA's Energy Transition Accelerator (ETA) programme. The programme, run since 2019, helps energy-using organisations map out a pathway to meet long term energy reduction goals – and provided a strong foundation to work from.

Otago is well set up to accommodate new electricity demand from most RETA process heat sites. The report also highlights the significant role local forestry biomass may play. Identifying now what the regional split is likely to be across biomass and electricity will help with investment in regional infrastructure and supply chains, including how it is prioritised and staged.

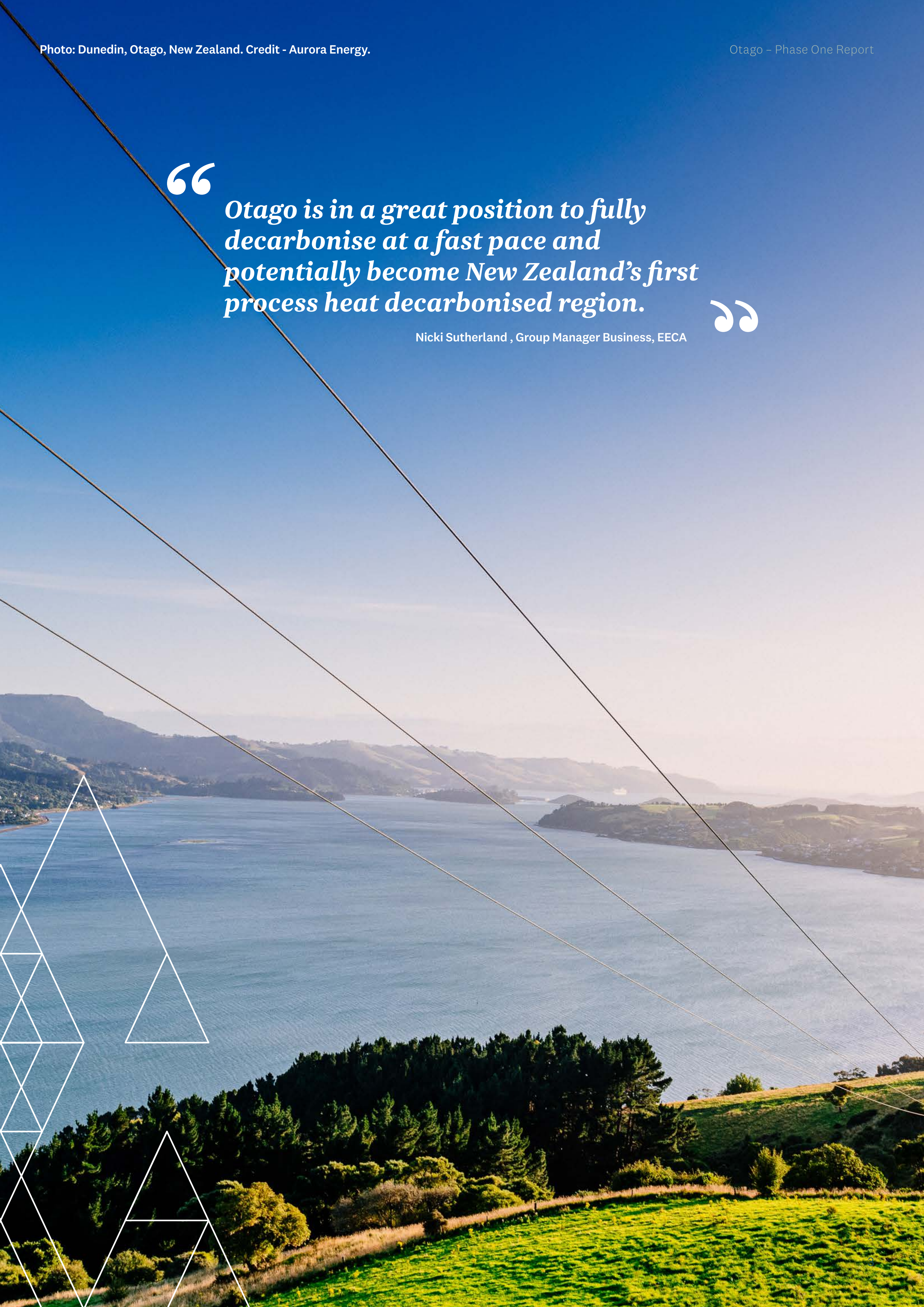
Taking a collaborative approach will accelerate efforts to reduce the region's carbon footprint and help it thrive. We are proud to have worked alongside Business South and several key groups including our RETA report workstream leads Transpower, Aurora, PowerNet, regional forestry companies and wood processors, electricity generators and retailers, and medium to large industrial energy users, to develop this Otago RETA report.

Otago is in a great position to decarbonise with a relatively small emissions profile and no major supply side constraints for either biomass or electricity. This means Otago can fully decarbonise at a fast pace and potentially become New Zealand's first process heat decarbonised region. Ready for a low-emissions economy.

Nicki Sutherland
Group Manager Business, EECA

EECA

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



> *Otago is in a great position to fully decarbonise at a fast pace and potentially become New Zealand's first process heat decarbonised region.*
>
> Nicki Sutherland , Group Manager Business, EECA

2 Acknowledgements

This Regional Energy Transition Accelerator (RETA) has involved a significant amount of time, resource and input from a variety of organisations. We are especially grateful for the contribution from the following organisations:

- Process heat users throughout Otago
- Business South
- Local lines companies Aurora and PowerNet
- National grid owner and operator Transpower
- Regional forestry companies
- Regional wood processors
- Electricity generators and retailers

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

- **Lumen** – process heat demand-side assessment
- **Ahikā and Margules Groome** – biomass availability analysis
- **Ergo Consultants** – electricity network analysis
- **EnergyLink** – electricity price forecast
- **Wayne Manor Advisory** – report collation, publication and modelling assistance

The Otago region is the focus for New Zealand's fourth Regional Energy Transition Accelerator (RETA).

Otago – New Zealand

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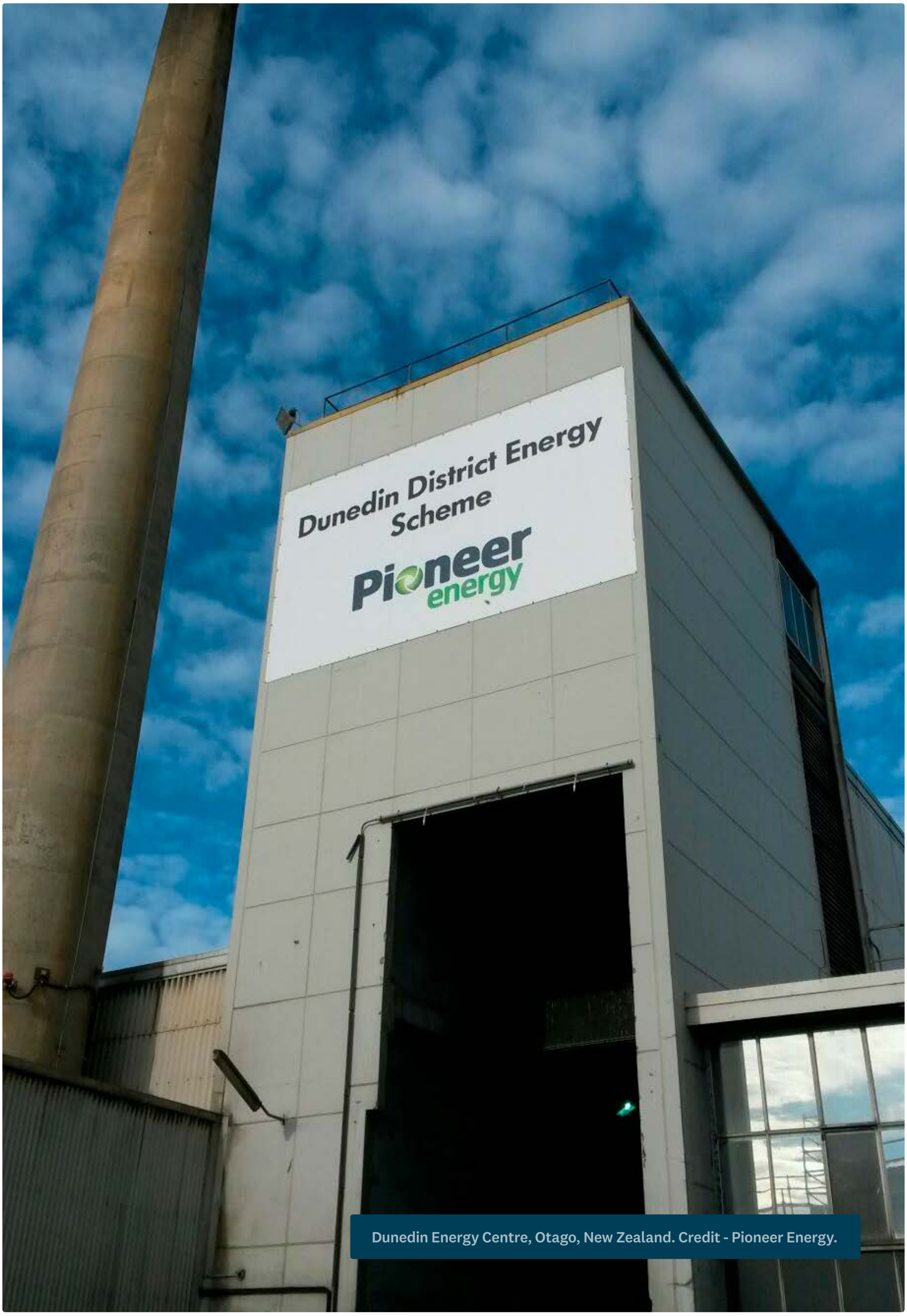


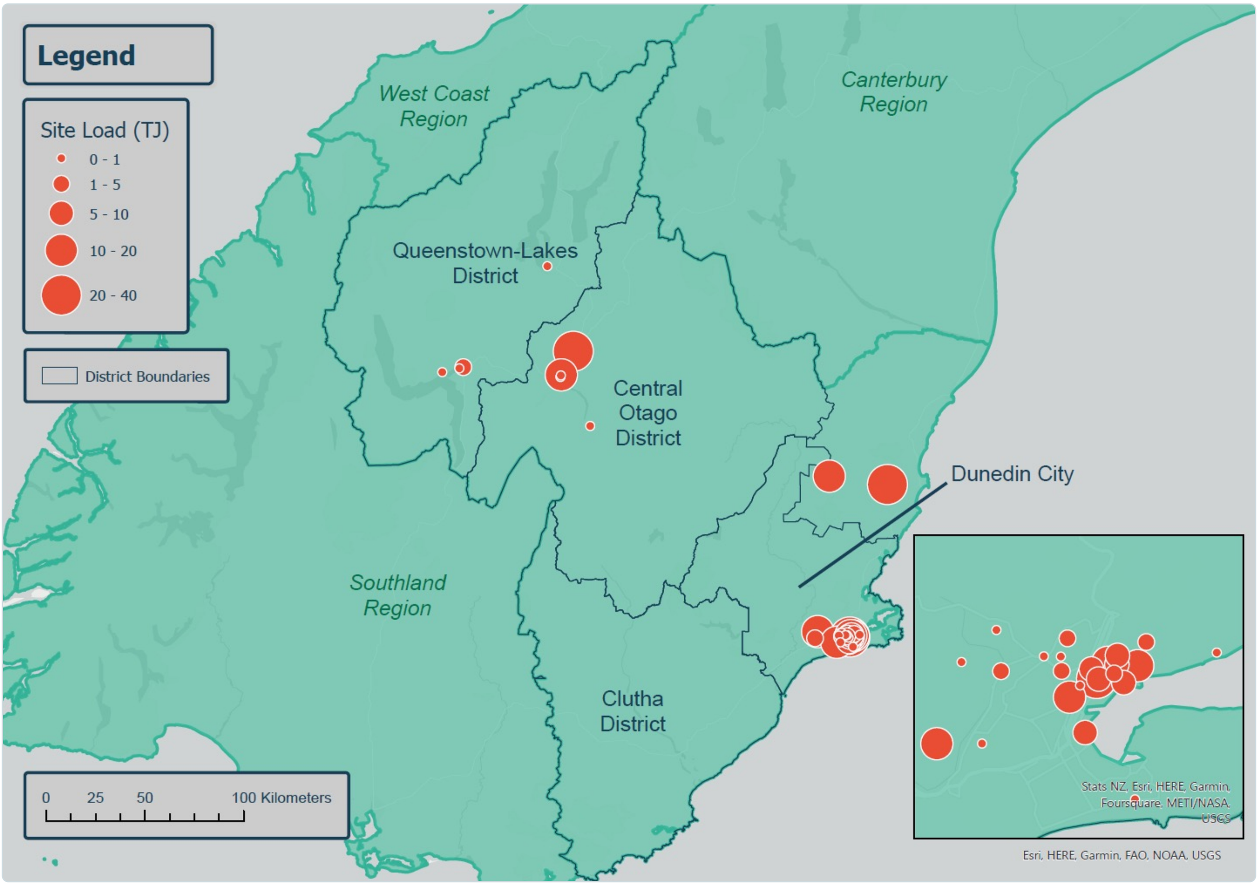
Dunedin Energy Centre, Otago, New Zealand. Credit - Pioneer Energy.

4 Executive summary

This report summarises the results of the planning phase of the Otago Regional Energy Transition Accelerator.

The Otago region covers Dunedin City, Queenstown-Lakes District, and Central Otago District (Figure 1).

Figure 1 – Map of area covered by the Otago RETA



The 51 sites covered span the dairy, meat, industrial and commercial[1] sectors. These sites either have process heat equipment larger than 500kW (i.e. process heat equipment details have been captured in EECA's Regional Heat Demand Database) or are sites for which EECA has detailed information about their decarbonisation pathway[2]. **Together, these sites collectively consume 746TJ of process heat energy, primarily in the form of coal, and currently produce 59kt per year of carbon dioxide equivalent (CO_2e) emissions.**

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

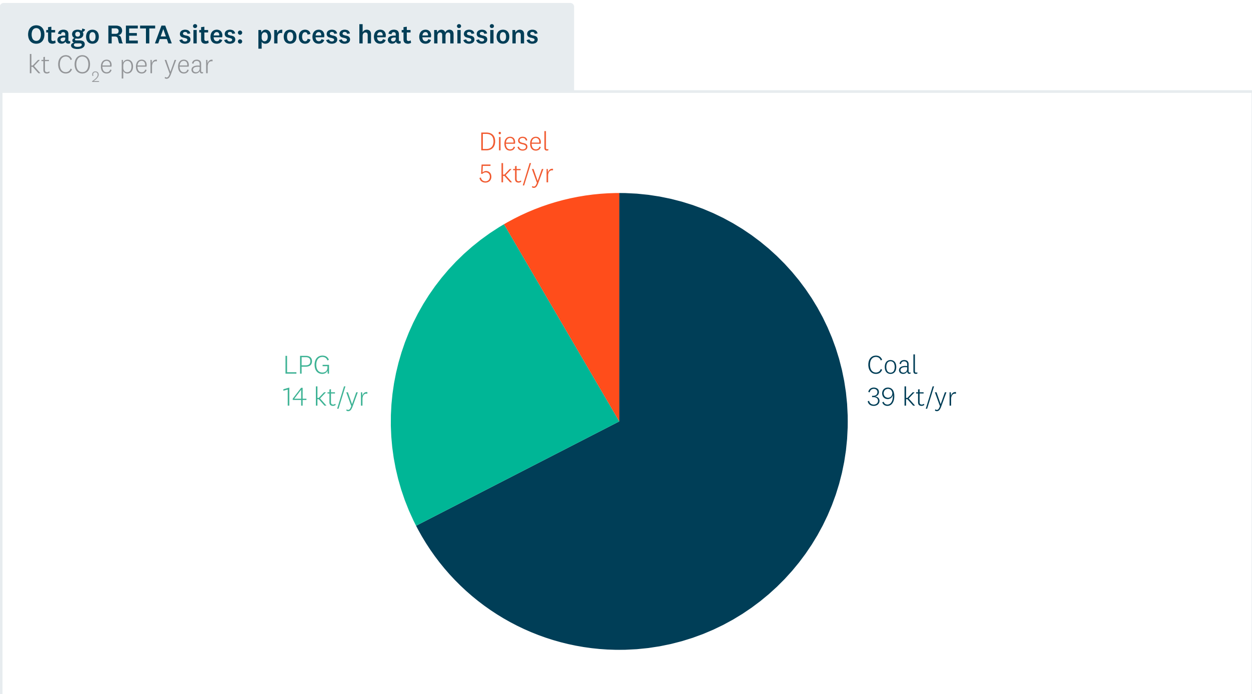
[2] That is, process heat equipment details have been captured in an ETA opportunities assessment report.

Table 1 – Summary of Otago RETA sites fossil fuel process heat demands and emissions

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand today (TJ/yr)	Process heat annual emissions (kt CO_2e/yr)
Meat	2	10	24	86	7
Industrial	11	47	95	341	26
Commercial	38	51	89	319	26
Total	**51**	**108**	**207**	**746**	**59**

The majority of the Otago RETA emissions come from coal (Figure 2).

Figure 2 – 2020 annual emissions by process heat fuel in Otago RETA. Source: EECA

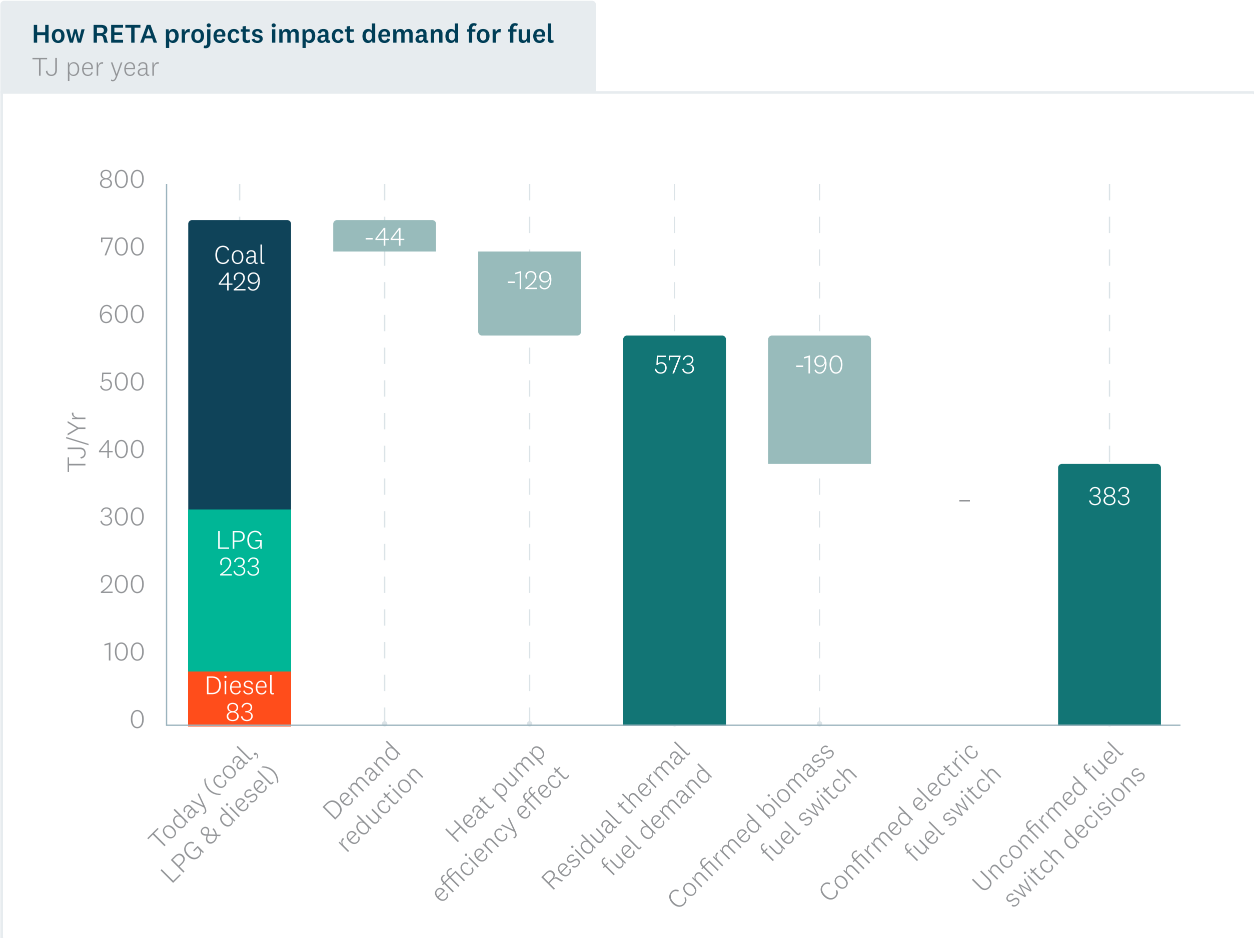


The objective of the Otago RETA is to eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

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

Figure 3 illustrates the potential impact of RETA sites on regional fuel demand, both as a result of decisions where investment is already confirmed, and decisions yet to be made.

Figure 3 – Potential impact of fuel switching on Otago fossil fuel usage, 2022-2037. Source: EECA



This report looks at the impact of 79 emissions reduction projects across the 51 sites – covering demand reduction, heat pump efficiency, and fuel switching projects. Further, it investigates the regional availability of biomass and electricity to replace coal and diesel. Combining these two analyses – demand-side and supply-side – we can provide the indicative economics of each of the 79 process heat decarbonisation decisions.

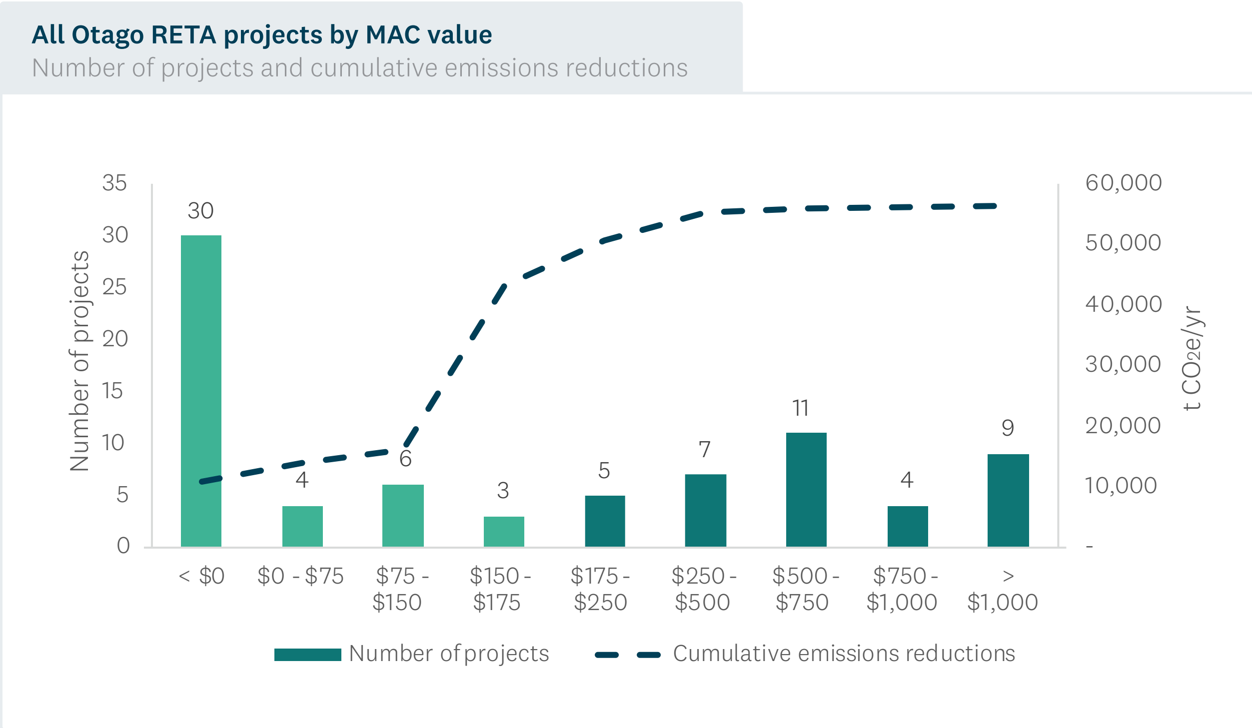
There are a range of decision criteria that individual organisations may use to determine the timing of their decarbonisation investments. Decisions are impacted by available finance, product market considerations, strategic alignment, and other factors. It is challenging to incorporate many of these into a single analysis of the 'economics' of a decision.

Rather than attempt to include all these factors, we use a global standard 'marginal abatement cost', or MAC, to quantify the cost to the organisation of decarbonising their process heat. This is expressed in dollars per tonne of CO_2e reduced by the investment.

4.1 At expected carbon prices, 77% of emissions reductions are economic[3]

Figure 4 summarises the MACs associated with each decision, and the emissions reduced by these projects.

Figure 4 – Number of projects by range of MAC value. Source: EECA

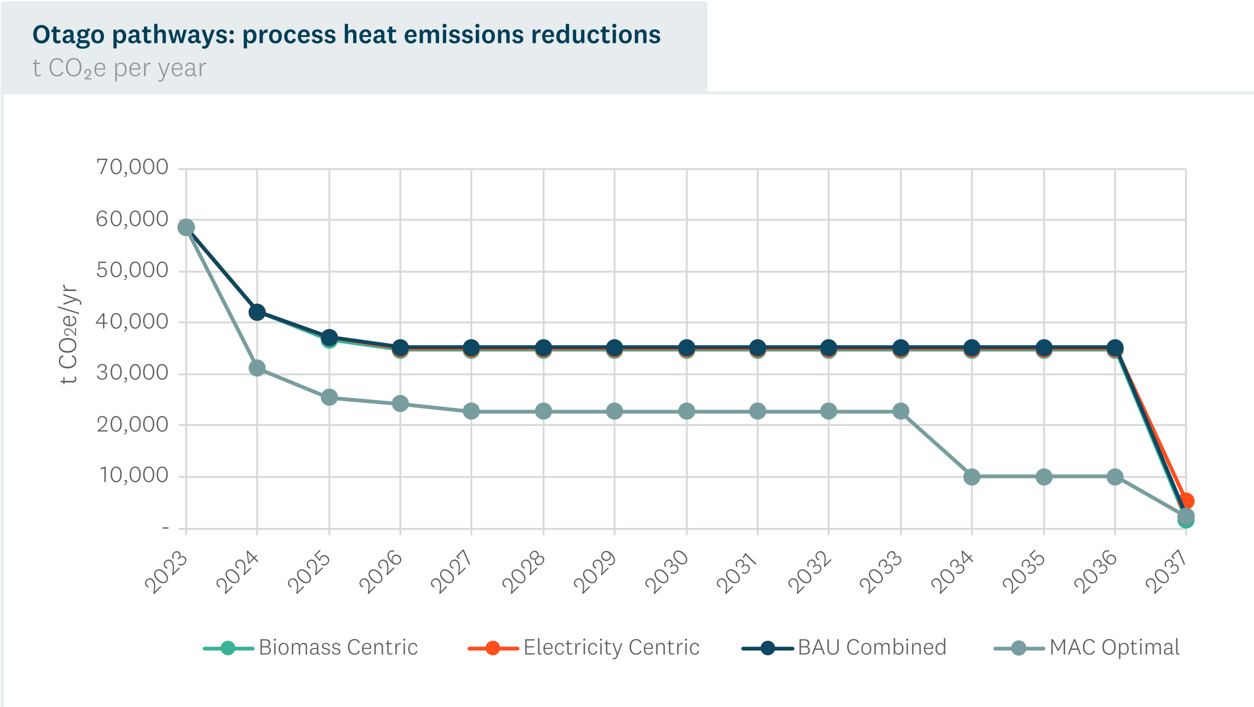


Out of 59kt of process heat emissions covered in the Otago RETA, 48kt (77%) have marginal abatement costs (MACs) less than $166/tCO_2e$. Based on an expectation the carbon prices will follow the Climate Change Commission's Demonstration Pathway, these emissions reduction projects would be economic prior to 2037.

Compared to a scenario where each of these projects was executed based on the organisations' current plans (a BAU pathway), executing these projects using a commercial MAC decision-making criteria ('MAC Optimal') would accelerate decarbonisation, and reduce the release of long-lived emission by 196kt over the 15-year period of the RETA analysis (Figure 5).

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

Figure 5 – Simulated emissions using Electricity Centric, Biomass Centric, BAU Combined and MAC Optimal pathways. Source: EECA



MAC values for each potential fuel – and thus the optimal fuel, and timing of investment – is driven by both the capital costs, and ongoing operational costs, of the investments. For the 14 unconfirmed fuel switching projects, operating costs are more important for electrification, while biomass MAC values in Otago are more driven by total capital costs[4]. Hence a focus for companies considering electrification should be to find ways to reduce the retail price and network charges paid for electricity. The ability to enable flexibility in consumption – even just the ability to shift their demand forward or back by a small number of hours – could have a material effect on the overall economics of the project.

We tested a range of sensitivities on this modelling – higher and lower electricity prices, government co-funding, and different decision-making metrics. While the pathway of emissions reduction was relatively unaffected (noting that government co-funding accelerated emissions reductions), these sensitivities did change the modelled decisions for some process heat users. The prospect for some inland-Otago process heat users to face higher transport costs for biomass switched their decision to electricity.

Government co-funding had a relatively modest impact on the pathways, if it is assumed that businesses decisions reflect pure economics. However, it is acknowledged that many businesses have constraints on the amount they can borrow, irrespective of rates of return. They may also have internal competition for that available capital and need to prioritise spend or need to align capital decisions with asset management timeframes. The presence of decarbonisation co-funding may overcome these wider constraints or cause decarbonisation projects to be prioritised, even if it has a relatively small effect on the project's economics. Government support may also enable these projects to occur more quickly than the economically rational timeframe.

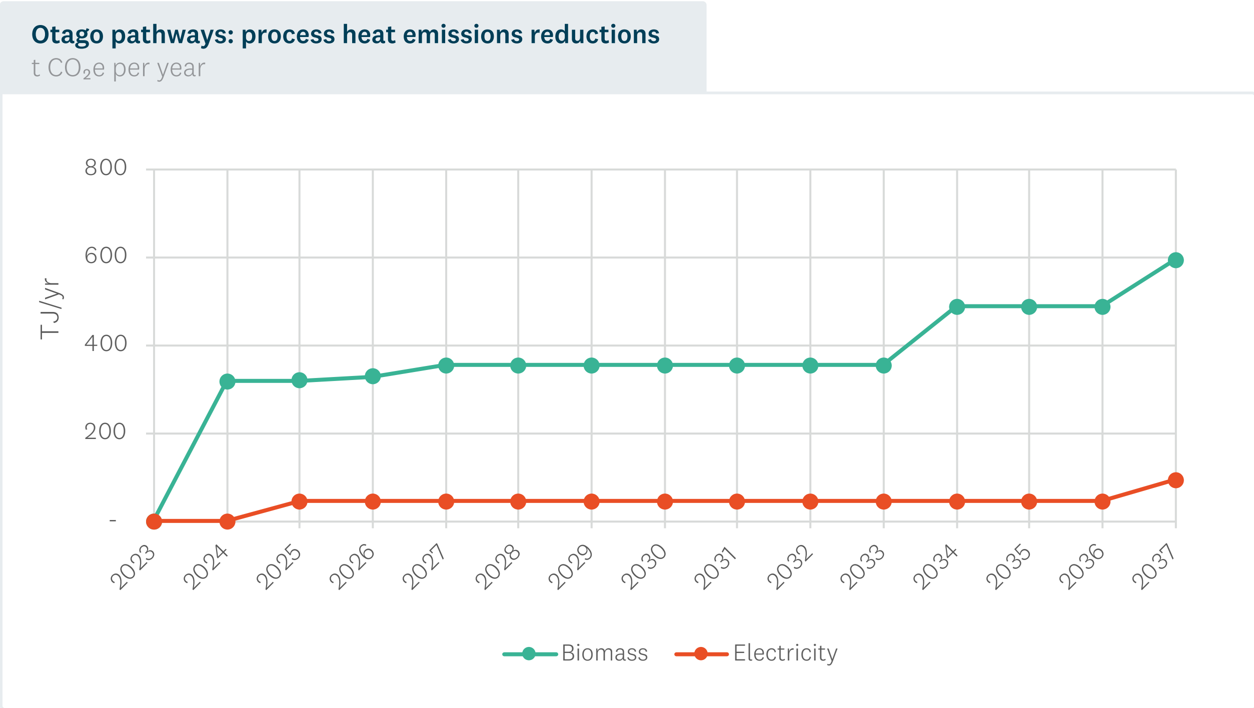
The sensitivity analysis reinforced that process heat users should refine their understanding of their requirements, supply, logistics, and costs for both electricity and biomass before committing either way. This includes early and regular engagement with supply organisations (foresters and electricity companies).

[4] This statement is specific to Otago and not a general statement about the difference between electricity and biomass. See discussion in Section 7.1.5.

4.2 What emissions reductions mean for fuel switching

From a supply-side perspective, the MAC Optimal pathway results in 14% of the process heat energy being supplied by electricity, and 86% by biomass (Figure 6).

Figure 6 – Electricity and biomass demand in MAC Optimal pathway. Source: EECA



While the fuel switching decision is typically the most significant in terms of energy usage and emissions reduction, it is important to recognise the impact that demand reduction and heat pump efficiency projects have on the overall picture of the Otago process heat decarbonisation.

As shown in Figure 3 above, investment in demand reduction and heat pumps would meet 23% of today's Otago energy demands[5] from process heat, which in turn reduces the necessary fuel switching infrastructure required: thermal capacity required from new biomass and electric boilers would be reduced by 15MW if these projects were completed. We estimate that demand reduction and heat pumps would avoid investment of $15M to $23M in electricity and biomass infrastructure.

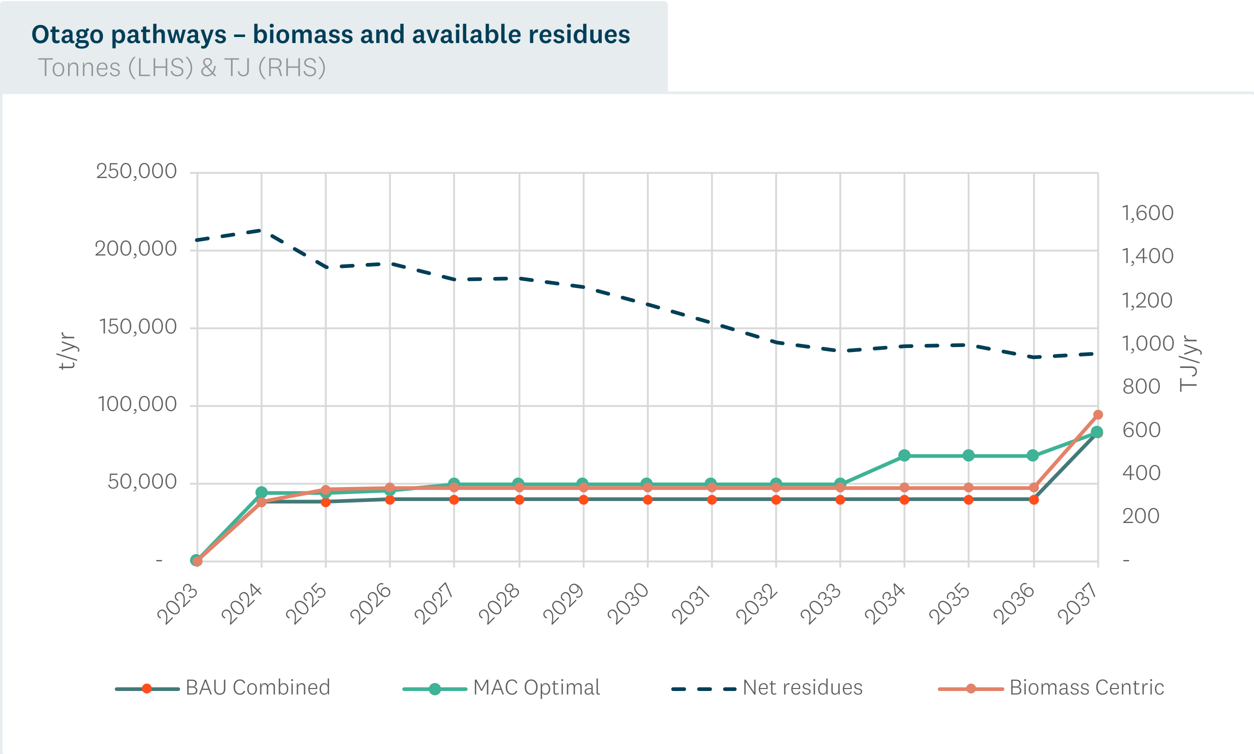
4.2.1 Biomass

Irrespective of the pathway, all biomass fuel switching projects, in aggregate, can be supplied by a combination of surplus processing residues and a pragmatic estimate of harvesting residues[6] (Figure 6).

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

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

Figure 7 – Growth in biomass demand under MAC Optimal and Biomass Centric[7] pathways. Source: EECA



Our analysis suggests that, over the next 15 years, the MAC Optimal process heat market demand for these residues could be between $50M and $80M (on a cost basis[8]), including chipping, storage, and transport.

Should more fuel switching decisions choose biomass than what we have modelled in the MAC Optimal pathway, minor species may have to be harvested for bioenergy. However, the analysis suggests that process heat users looking to biomass should have a high degree of confidence that their needs can be met from resources within the region, and without the need to divert significant quantities from existing export markets. That said, neighbouring regions could also seek biomass from the forests that are included in the Otago RETA assessment, where transport costs and logistics make this practical[9]. The potential for inter-regional trade in biomass will be considered when all South Island RETA reports are complete, and the island as a whole can be analysed.

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

[8] Cost of wood chip delivered to process heat user at $13.50/GJ (wet wood), per Section 8.7. Does not include costs associated with processing into (for example) wood pellets.

[9] Reinforcing this, we note that the forest resources for the Clutha district were included in the Otago assessment, while a small number of process heat users in the Clutha district were accounted for in the Southland RETA report.

4.2.2 Electricity

Nationally, generation investment is expected to keep pace with the increase in national demand growth that arises from decarbonisation. This is likely to lead to modest increases in electricity prices for process heat consumers over the next 15 years. However, even allowing for a 10% rise in real electricity prices over that period, 14% of the energy required under the MAC Optimal pathway chooses electricity as the best fuel. Our sensitivity analysis suggests this outcome is relatively robust under different electricity price scenarios. Part of this is due to very favourable retail electricity offers in the market today, some targeted at process heat users who convert to electricity.

While the national electricity market is expected to deliver the necessary generation to meet the increased demand from process heat, the 51 sites in the RETA study rely on an extensive network of transmission and distribution infrastructure to deliver this power to their site.

Otago is home to two distribution network owners – electricity distribution businesses (EDBs) – who maintain the myriad assets that connect consumers to Transpower's national grid. These EDBs also work with Transpower to ensure that the national transmission grid is sufficient to cope with increased demand. These entities are facing increased demands from the region as consumers consider the electrification of transport and process heat.

The critical aspect of electricity demand growth that concerns network owners is not the growth in electricity consumption resulting from new electric boilers and heat pumps (around 20% of current Otago electricity demand if all process heat electrified), but rather the impact on the network's peak demand that arises from electrification of boilers.

Figure 8 – Potential increase in Otago peak electricity demand under MAC Optimal and Electricity Centric pathway. Source: EECA

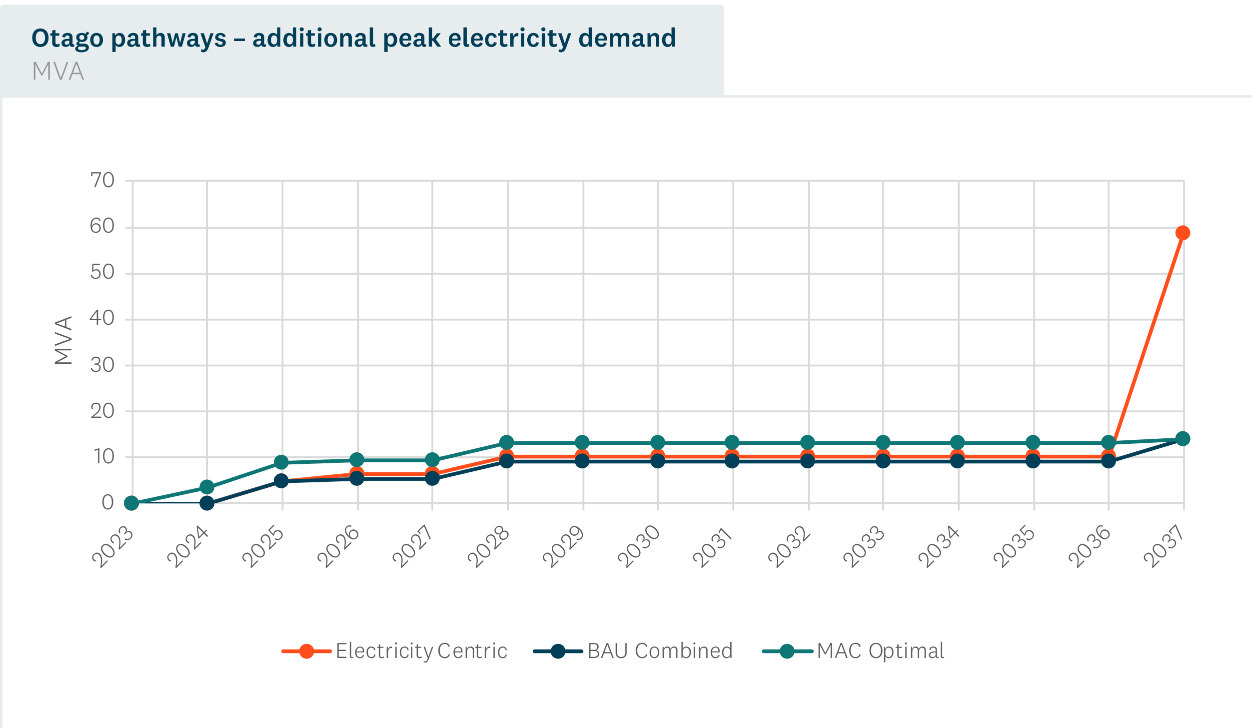


Figure 8 shows that, should all unconfirmed process heat users in Otago convert to electrode boilers (the Electricity Centric pathway), the increase in demands on the two Otago EDBs could be significant by 2037[10]. However, if the decision making follows the commercial guidelines in our MAC Optimal pathway, the network requirements are likely to be around 75% lower than the Electricity Centric pathway. Table 2 breaks this down by EDB.

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

EDB	Electricity Centric pathway		MAC Optimal pathway	
	Connection capacity (MW)	Connection cost ($M)	Connection capacity (MW)	Connection cost ($M)
Aurora (Dunedin)	32	$4.9	10	$1.0
Aurora (Central)	14	$3.6	4	$-
Aurora (Queenstown)	1	$0.1	0.2	$-
OtagoNet	12	$4.4	-	$-
Total	**59**	**$13**	**14.2**	**$1.0**

Relative to their current peak demand (63MW[11]), OtagoNet sees a 20% increase in network demand under the Electricity Centric pathway, but would be unaffected by the MAC Optimal pathway. Aurora would see between a 5% (MAC Optimal) and 20% (Electricity Centric) increase in peak demand.

The extent to which this increase in peak demand triggers investment in network capacity depends on a number of factors, such as existing spare capacity and security of supply requirements.

From the process heat user's perspective, this report also analyses the cost and complexity of securing sufficient local capacity to electrify their boilers.

[10] This chart shows the cumulative increase in peak demand assuming all electrode boilers peak at the same time. Section 9 discusses a more realistic view which considers the natural diversity between process heat users in terms of when each is likely to peak. This results in a slightly lower peak demand requirement from the networks.

[11] OtagoNet Joint Venture, Information Disclosure 2022, Schedule 9e.

For 23 of the 35 sites considering electrification, the 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Most of these minor upgrades would have connection costs under $600,000 (and many under $200,000) and experience connection lead times of less than 12 months.

More substantial upgrades to the distribution network are required for 14 sites, with commensurately higher costs (between $1M and $7M) and longer lead times (12-24 months).

Overall, decarbonising Otago process heat through electrification appears very achievable and is unlikely to be slowed by network constraints. This is particularly helped by the connection of new demands not being expected to trigger transmission upgrades.

Both the cost faced by process heat users to connect their electric boilers to the network, and the wider network upgrades that Transpower and the EDBs are contemplating, could be reduced by harnessing the potential for process heat users to be flexible about *when* they use their boilers. We highlighted above how demand reduction and heat pumps have reduced the need for thermal capacity by around 15MW. Similarly, if process heat users could shift some or all of their electricity consumption away from critical peak times on the network (usually winter mornings and evenings), or maintain an alternative supply of fuel, a greater degree of cost savings could be experienced.

While the ability to shift demand relies on having some degree of interruptibility or storage in the process, some studies have estimated sites could save between 8% and 18% of their electricity procurement costs, and between $150,000 and $300,000 per MW of electricity infrastructure costs every year.

4.3 Recommendations and opportunities

Our analysis has highlighted a range of opportunities and recommendations which would improve the overall process heat decarbonisation 'system'. These recommendations are summarised here.

Recommendations to improve the use of biomass for process heat decarbonisation:

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

Recommendations to improve the use of electricity for process heat decarbonisation:

- **EDBs should proactively engage with process heat users to understand their intentions and help process heat users obtain a greater understanding of required network upgrades, cost, security levels, possibilities for acceleration, use of system charges and network loss factors. EDBs should ensure Transpower and other stakeholders (as necessary) are aware, at an early stage, of information relevant to their planning.**
- **EDBs should develop and publish clear processes for how they will handle: connection requests in a timely fashion; opportunities for electrified process heat users to contract for lower security; and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).**

- **EDBs and process heat users should 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.**

- **To support this early engagement, EDBs should explore, in consultation with process heat users and EECA, 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.**

- **Retailers, EDBs and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.**

- **EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.**

- **EECA should expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**

Recommendations to assist process heat users with their decarbonisation decisions:

- **Ministries (such as Ministry for the Environment) need to work with reputable organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.**

- **Process heat users should enquire about government co-funding where the economics of decarbonisation are challenging; where they are economic, EECA encourages organisations to explore the potential for self-funded acceleration.**

5 Introduction

5.1. The Energy Transition Accelerator programme

EECA has run the ‘Energy Transition Accelerator’ (ETA) programme since 2019. The programme aims to support New Zealand’s largest businesses to make technically and economically viable process heat decarbonisation decisions and investments which support their energy transition pathway to a low-carbon future. EECA assists organisations in committing to a longer-term transition, based on the opportunities and risks on the economic and technological horizons. The ETA programme is designed to help businesses prepare for the future, by capitalising on the process heat energy and carbon saving opportunities that are in the pipeline now, and beyond 2030. An overview of the ETA programme is shown in Figure 9 below.

Figure 9 – Overview of ETA programme. Source: EECA

EECA-led phases

1 Exploratory engagement

- Senior-level expression of interest in long-term planning & commitments
- Energy transition and climate risk assessment

2 Initial assessment

- Kick-off sprint session | One2Five EM review
- Work with reviewer to provide energy and business data

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

Customer-led phases

3 Detailed analysis and pathway setting

- GHG accounting
- Extensive energy audit
- Feasibility studies
- Pinch analyses
- Energy management system enhancement
- ETA steering group established internally

4 Planning, implementation and review

- Develop and implement energy transition pathway plan
- Track/review/improve
- **Celebrate success**

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

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

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

EECA's Regional Energy Transition Accelerators (RETAs) are the projects that provide this regional perspective.

5.2 The Otago RETA

There are two stages of a RETA project – planning, and implementation. This report is the culmination of the RETA planning stage in the Otago region.

The first planning phase aims to:

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

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

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

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

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

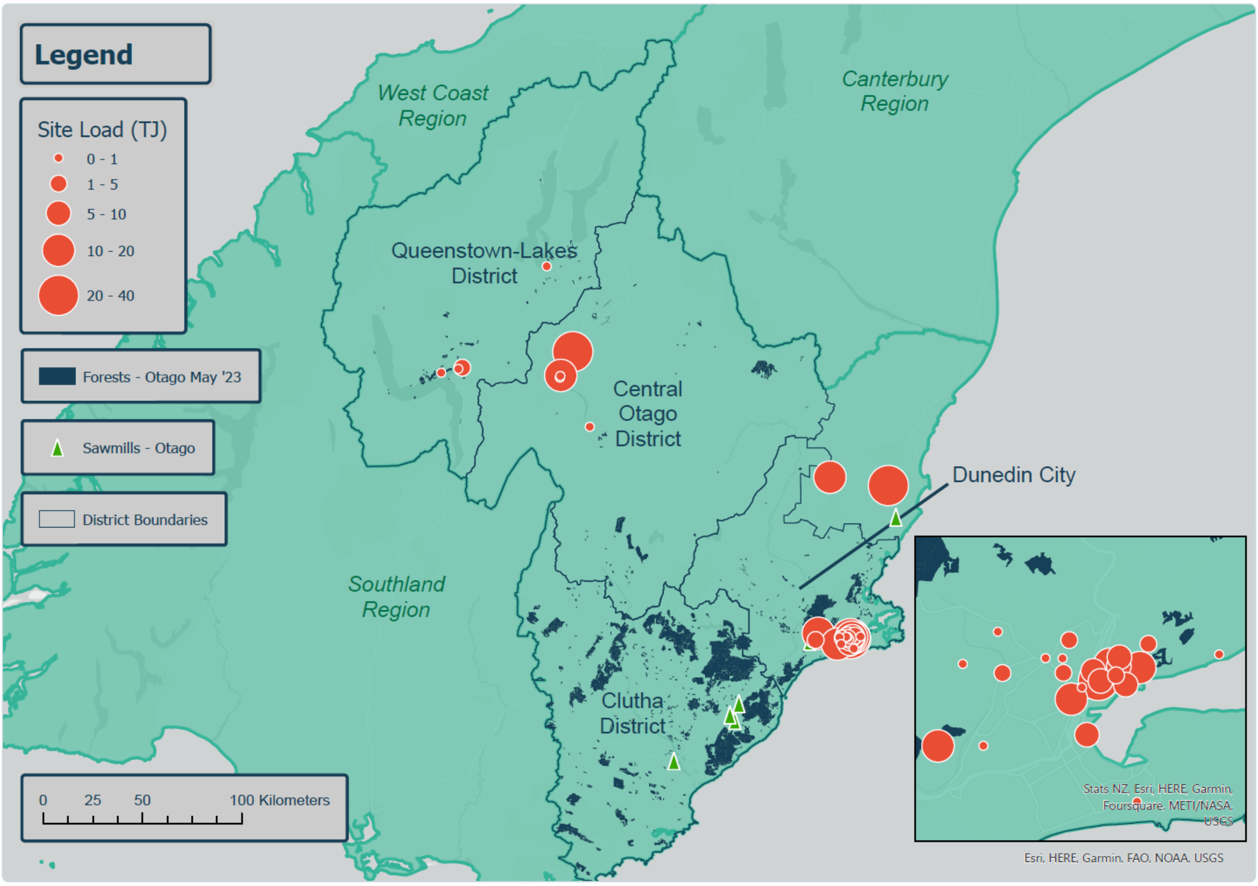
Central Otago, New Zealand. Credit - Aurora Energy.

6 Otago process heat – the opportunity

6.1 The Otago region

The area of study encompasses the Queenstown Lakes, Central Otago, Clutha and Dunedin areas. Figure 10 illustrates the region considered in this report, with the process heat sites located and sized according to their annual energy requirements.

Figure 10 – The Otago RETA region

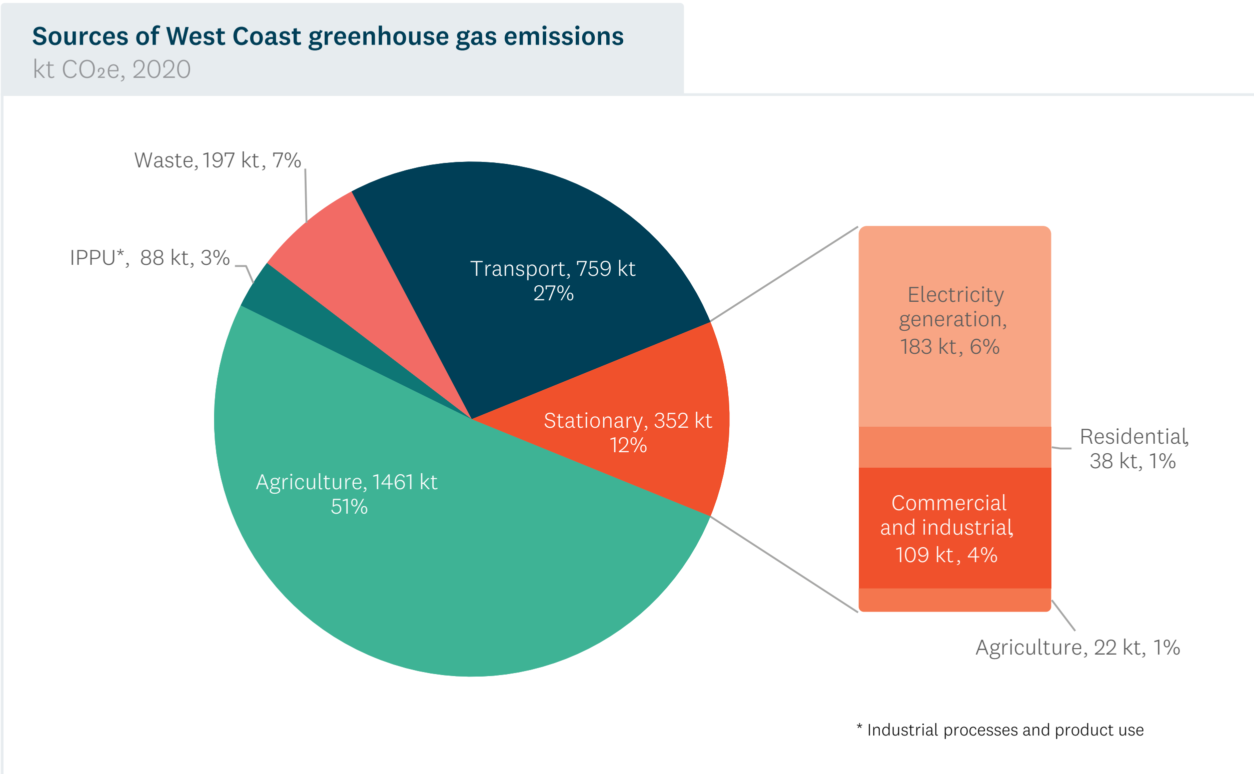


6.2 Otago emissions today

The Otago Regional Council (ORC) commissioned a regional greenhouse gas inventory in order to obtain a more detailed view of the sources of the region's emissions. ORC's assessment included the Clutha District, but our analysis below removes Clutha's emissions because the district was included in the Southland RETA, not the Otago RETA. For the remainder of this section, any reference to 'Otago' should be taken to mean the RETA boundaries, rather than the official regional boundaries.

Like much of New Zealand, Otago greenhouse gas emissions (expressed in carbon dioxide equivalent, CO_2e) are dominated by agricultural emissions, making up 1,461kt (51%) of emissions out of the region's total emissions of 3,205kt (Figure 11). Energy is the second largest emitting sector, with 1,118kt (39%), split between transport and stationary energy.

Figure 11 – Emissions inventory for Otago. Source: Otago Regional Council Regional Greenhouse Gas Inventory



Stationary energy is a general category for any use of energy that doesn't relate to road, marine, rail or air transport, and is usually a combination of electricity and the direct use of fossil fuels for creating heat (heavily dominated by process heat). ORC reports that stationary energy is 32% of energy-related emissions on the Otago region.

Figure 11 breaks stationary energy emissions down into sector sources. Electricity generation and residential emissions are outside the focus of the RETA study. We expect that the majority of agriculture emissions relate to off-road vehicle use or diesel generators. Hence we conclude that the majority of the remaining 109kt of commercial and industrial emissions would be 'process heat'.

The ORC study was based on data from 2019. Since then, the Dunedin Energy Centre has switched one of its boilers to biomass, which is estimated to have reduced commercial and industrial process heat emissions by around $10ktCO_2e$, to 99kT.

6.2.1 Emissions coverage of Otago RETA

The Otago RETA covers a total of 51 process heat sites spanning dairy, meat, industrial (e.g. sawmills) and commercial (predominantly facility heating). To target the greatest level of emissions reduction opportunities, the sites selected represent all fossil fuelled process heat equipment above 500kW and any other sites (e.g. schools) where EECA had information from various programmes (such as the Regional Heat Demand Database (RHDD)[12] and ETA) up to 2022. These sites are summarised in Table 3.

The majority of the sites are commercial in nature, but the majority of emissions arise from the industrial sector.

Table 3 – Summary of fossil fuelled process heat sites included in the Otago RETA. Source: EECA

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand today (TJ/yr)	Process heat annual emissions (kt CO_2e/yr)
Meat	2	10	24	86	7
Industrial	11	47	95	341	26
Commercial[13]	38	51	89	319	26
Total	**51**	**108**	**207**	**746**	**59**

Overall, the Otago RETA sites in aggregate account for 59kt of process heat greenhouse gas emissions, around 60% of the 99kt of commercial and industrial stationary energy emissions shown in Figure 11[14]. This is a relatively small proportion compared with other RETA analyses done to date. We expect this can be explained primarily by two reasons:

- The ORC inventory accounts for boilers larger than 100kW, whereas RETA focuses primarily on boilers larger than 500kW. We expect that a large proportion of the remaining 50kt of stationary emissions, not accounted for in the RETA sites, relate to boilers between 100kW and 500kW.
- There will be a component of commercial emissions that is a result of the use of LPG for cooking in commercial kitchens and restaurants, as well as for space and water heating in commercial buildings. We expect that this is particularly the case for regions such as Otago which have a major urban centre (Dunedin) as well as large tourism centres (Queenstown and Wanaka).

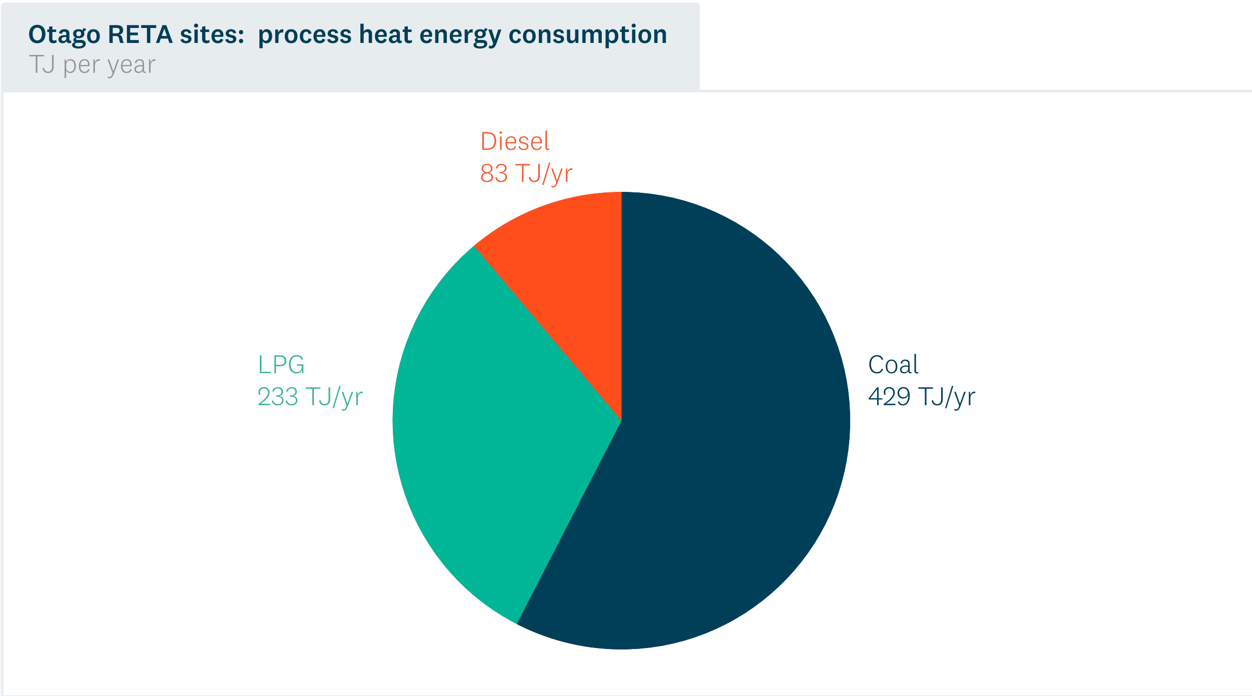
We now consider the source of RETA emissions by fuel. Current process heat requirements met by direct use of fossil fuels (coal, diesel and LPG) on RETA sites consume 746TJ of process heat energy per year (Figure 12).

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

[13] Commercial includes process/space heat from the Dunedin Energy Centre.

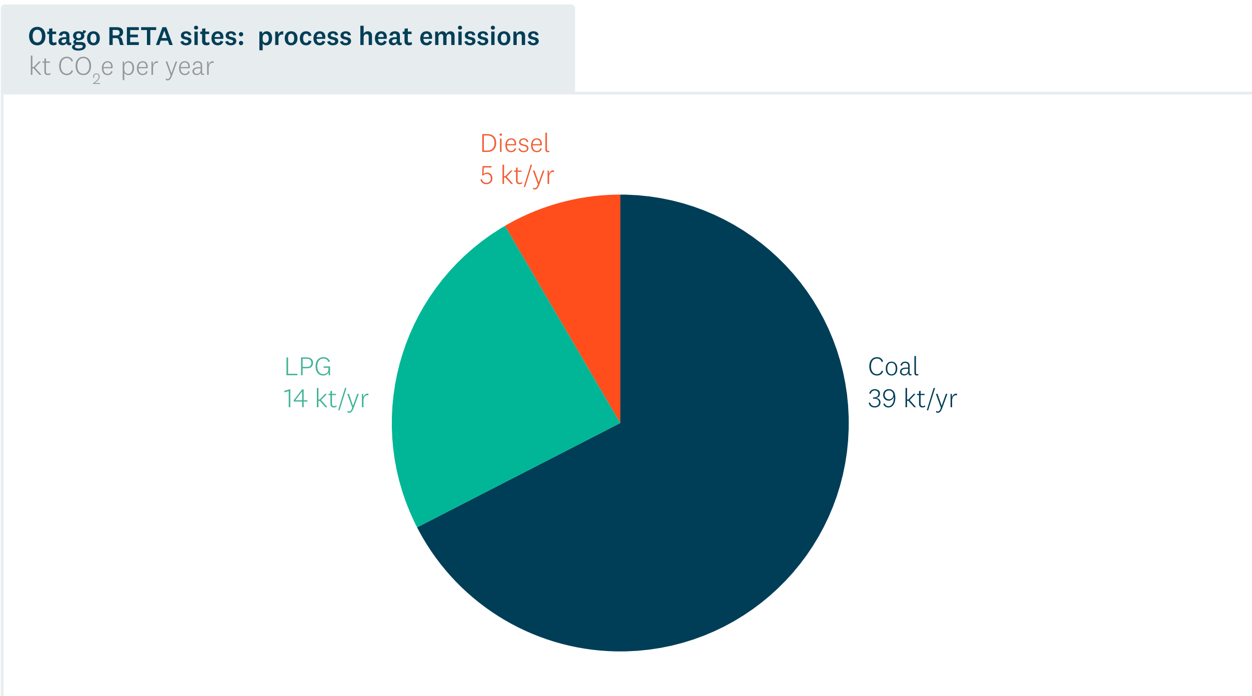
[14] Adjusted for the post-study reduction in emissions from the Dunedin Energy Centre, as discussed above.

Figure 12 – 2020 annual process heat fuel consumption in Otago RETA. Source: EECA



The majority of Otago RETA emissions[15] come from coal, while around 25% comes from LPG (Figure 13).

Figure 13 – 2020 annual emissions by process heat fuel in the Otago RETA. Source: EECA



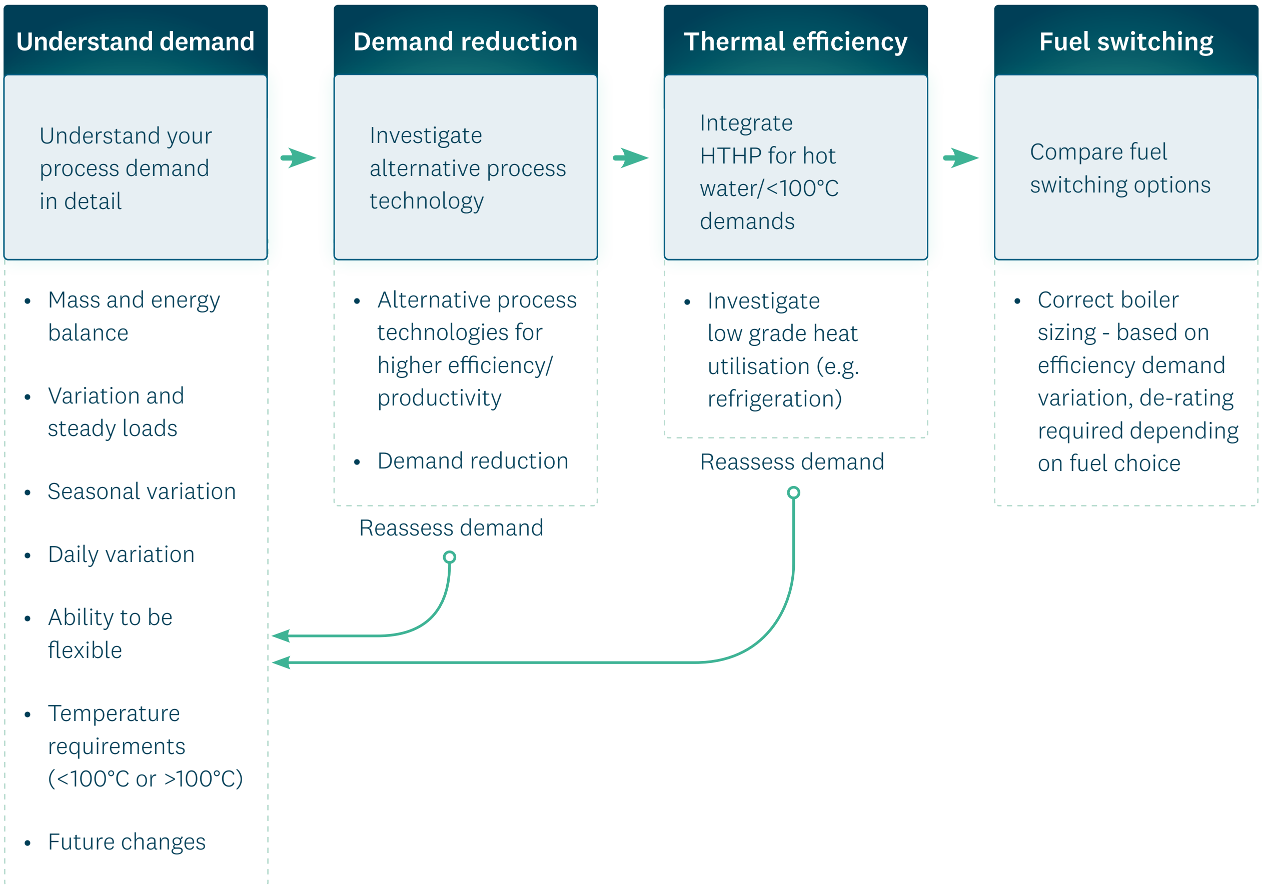
[15] Emissions factors used for fossil fuels are as follows (t CO_2e per t of fuel): Lignite: 1.43; Sub-bituminous coal: 2.01; Diesel: 2.26; LPG: 3.03.

6.3 Process heat decarbonisation – how it works

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

Figure 14 provides an overview of the main steps in the decarbonisation decision making process.

Figure 14 – Key steps in process heat decarbonisation projects



As part of the fuel switching step above

Electricity

- Electrode boiler
- Network capacity increase required?
- Ability to flex demand to minimise cost
- Long-term electricity tariff
- Long-term carbon price

Biomass

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

6.3.1 Understanding heat demand

The importance of understanding the nature of a site's demand for process heat cannot be overstated. This includes understanding how it varies on an hourly, daily, weekly and seasonal basis. A comprehensive understanding of heat requirements will underpin all subsequent decisions regarding efficiency, demand reduction, and fuel switching.

An important aspect here, especially if electrification is to be considered properly, is the ability to be flexible in heat demand – can heat demand be interrupted or reduced for short periods of time (for example, through utilising hot water storage)? As will be discussed in Section 9.5, this flexibility can reduce the cost associated with any electricity network upgrades required to accommodate the project. It can also mean a financial reward for the process heat user through a variable ('time-of-use') electricity tariff. Similarly, this applies to biomass options as it may reduce the size of a boiler, which reduces the capital outlay required if a new boiler is contemplated.

With an understanding of the site's demand, there are four primary ways in which emissions can be reduced from the process heat projects covered by Otago RETA. For any given site, the four options below are not mutually exclusive – that is, a number of options could be executed. Some of the options below are precursors for others – for example, to minimise the cost of a new boiler, demand reduction projects should precede commitment to the new boiler size.

6.3.2 Demand reduction

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

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

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

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

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

Where a site has a range of heat requirements, heat pump projects should generally be considered prior to fuel switching as existing site heat can be utilised to decrease the required capacity of the new boiler. Depending on the site operations, a coefficient of performance (COP) of three to five can typically be achieved[18]. While not yet used in New Zealand, high temperature steam heat pumps producing 150°C heat[19] have the potential to decarbonise much of New Zealand's industry within the 15-year timeframe contemplated by EECA's RETA decarbonisation pathways for the Otago region (outlined in Section 10).

6.3.4 Fuel switching to biomass – boiler conversions or replacements

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

Two primary and interrelated decisions when switching to biomass are:

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

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

- If the site is converting an existing coal boiler, it may be able to be retrofitted to burn wood pellets or chip as a fuel. If a new boiler is contemplated, wood pellets, chip and hog are potential fuels.
- Wood pellets are a higher quality fuel and are more expensive, while wood chip and hog are lower quality fuels, but are more easily produced. Wood pellets require substantially more processing than other wood fuels, and bioenergy processing plants (e.g. pellet production) will likely have minimum levels of scale to be economic and may take time to be developed in the region.
- EECA has not considered in detail the logistical and emissions impact of transporting biomass but notes that wood pellets will have lesser transport requirements due to their higher energy density.

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

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

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

- Wood fuel must have a moisture content as specified in the fuel supply contract according to the design of the boiler. Out of specification fuel may impact the performance of the boiler and the overall process.
- Hog fuel is cheaper than wood pellets and chip but may require greater modification of existing storage and handling facilities which have been designed around coal. Due to the lower energy density of hog fuel compared to coal, more space (and likely a higher number of deliveries) is required to store it onsite.
- The available space on site is also important. Biomass fuel should be kept dry so larger, covered, storage facilities may be required compared to existing coal storage.

6.3.5 Fuel switching – electrification

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

A key consideration when assessing electrification projects is whether the increase in electricity demand from the site requires upgrades to the local or regional electricity network. The potential cost of such upgrades is considered in Section 9.

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

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

6.4 Characteristics of RETA sites covered in this study

As outlined above, there are 51 sites considered in this study. Across these sites, there are 108 individual projects spanning the three categories discussed in Section 6.3 – demand reduction, heat pumps and fuel switching. Table 4 shows the different stages of completion of the RETA process heat projects.

Table 4 – Number of projects in Otago RETA by category. Source: Lumen, EECA.

Status	Demand reduction	Heat pump efficiency	Fuel switching	Total
Completed	-	5	24	29
Unconfirmed	22	14	14	50
Total	**22**	**19**	**38**	**79**

The remainder of this report accounts for the 79 projects which have not been completed. Some have been confirmed by the process heat organisation (i.e. the organisation has committed to the investment and funding allocated) but are not yet completed. Approximately two thirds of the 79 projects are unconfirmed, in that the process heat organisation is yet to commit to the final investment.

6.5 Implications for local energy resources

All RETA decarbonisation pathways (presented in Section 7) expect that the 51 Otago RETA sites, representing 746TJ of coal, LPG and diesel process heat energy consumption in 2022, will have executed demand reduction projects (where not already completed) and switched to low emissions fuel[21] before 2037[22]. Allowing for the investments that have already been confirmed by process heat users, the rate at which the unconfirmed fuel choices are made are the subject of the rest of this report. Whichever way this occurs, the outcome has potentially significant implications for the use of various fuels and resources in the region.

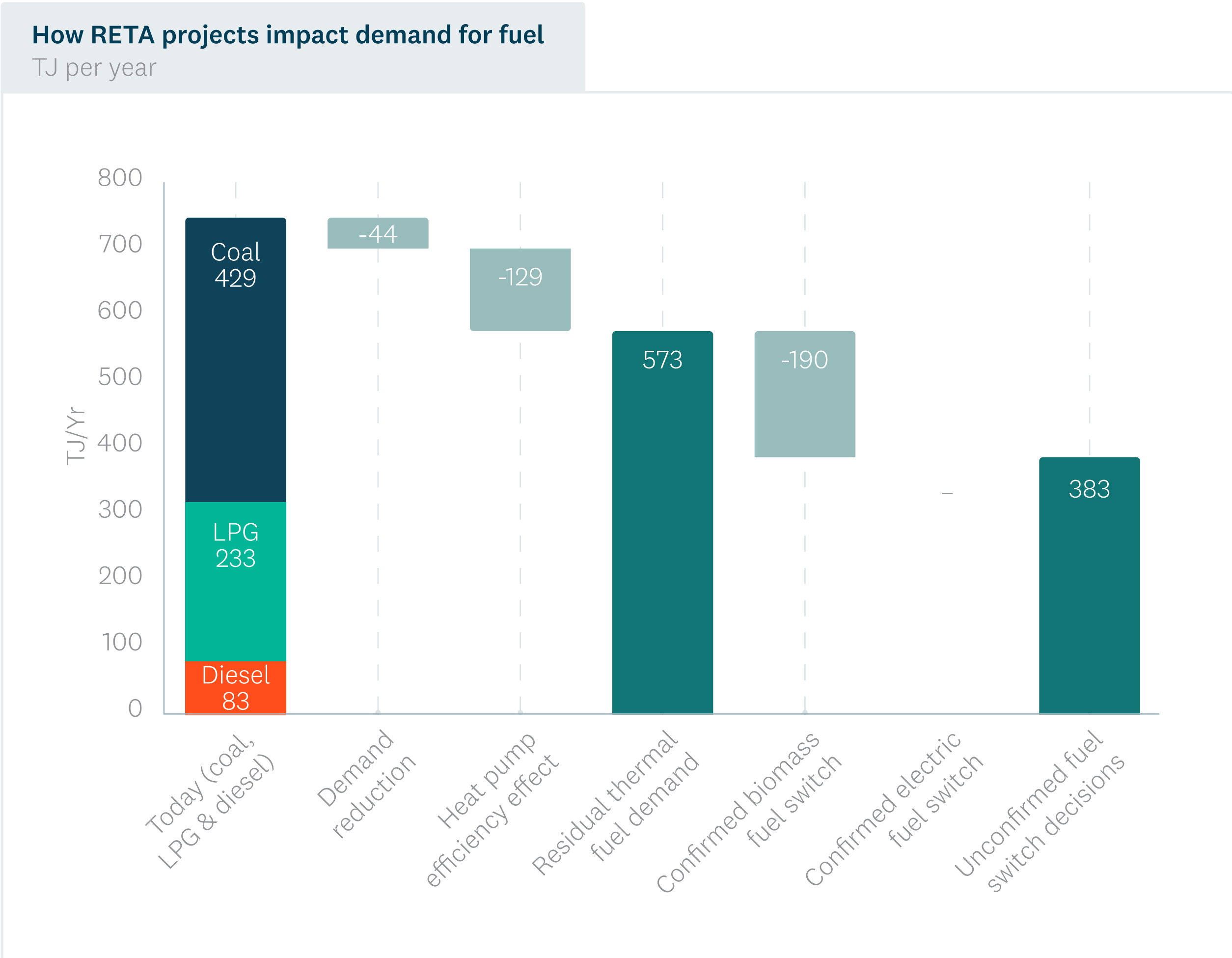
[21] Including any use of heat pumps to achieve increased efficiency.

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

As outlined above, demand reduction and heat pumps are key parts of the RETA process and, in most cases enable (and help optimise) the fuel switching decision. This RETA report has a greater level of focus on the fuel switching decision, though, due to the higher capital and fuel intensity of this decision. However, in assessing the required boiler capacity for each unconfirmed fuel switching project, this report assumes that every site has invested in a demand reduction project. Where applicable[23] it will also assume a heat pump will be installed – even for only part of the site heat needs – as this could see significant efficiencies achieved. These investments will reduce fossil fuel consumption, and thus the low-emissions fuel required for the remaining process heat needs.

These components are presented in Figure 15, to provide a picture of how fuel use may change over the period of the RETA study.

Figure 15 – Potential impact of fuel switching on Otago fossil fuel usage, 2022-2037. Source: EECA[24]



[23] That is, where there is a low temperature heat requirement. It will not assume a heat pump for sites that have confirmed a switch to biomass for low temperature heat needs.

[24] All of the demand reduction projects are unconfirmed at the time of writing. For heat pumps, only 3% are confirmed.

As 383TJ of fuel switching decisions are unconfirmed[25], the magnitude of change in biomass and electricity demand cannot be known with any precision. However, we can say:

- If all unconfirmed fuel switching decisions choose electricity, this – combined with confirmed electrification projects[26] – could result in an increase in instantaneous electricity demand of 58MW across Aurora and OtagoNet's networks, if all sites reached their maximum outputs at the same time[27]. This instantaneous demand would increase the coincident maximum demand experienced currently by both EDBs by around 20%[28]. These electrification decisions would also increase the annual consumption of electricity by 95GWh, approximately 5% of today's gross electricity consumption[29] in Otago.
- If all unconfirmed boiler fuel switching decisions choose biomass, this – combined with confirmed biomass projects – could result in an increase of 94,000t per year of biomass usage (see Section 8.7). Assuming sufficient resources were available, this is a seven-fold increase in the use of biomass for heat compared to our estimate that, today (in 2022), around 13,000t of biomass is used for heat.

These two scenarios paint the 'end points' of a spectrum of mixes of biomass and electricity fuel switching decisions. The reality is that each process heat user will make fuel switching decisions based on their own requirements and drivers.

The degree to which the resulting fuel demand – in a range of scenarios – can be met through local resources (electrical or biomass-related) is considered in Section 7.

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

[25] The figure of 383TJ is slightly higher than the sum of demands in Table 5 below. This is primarily due to the difference in efficiency between existing boilers and new boilers. The figures in Table 5 represent the fuel demand assuming a higher efficiency associated with a new boiler, whereas Figure 16 represents today's demand from the existing boilers.

[26] These figures also include the increase in electricity demand from expected installation of high temperature heat pumps for low temperature heat applications.

[27] It is unlikely that all sites reach their peak demands at the same time. See Section 9.4 for an analysis.

[28] Combined peak coincident demand across Aurora and OtagoNet is around 290MW, according to EDB disclosure information.

[29] Otago's current electricity consumption is around 1,700GWh per year (source: emi.ea.govt.nz). A portion of gross electricity consumption in Otago (114GWh according to Aurora's 2021 disclosures) is supplied by distributed generation that is not directly connected to the national grid.

Table 5 – Summary of Otago RETA sites with fuel switching requirements. Green shading indicates confirmed projects; red highlighting indicates the preferred fuel option using a commercial decision-making criteria developed in Section 7.

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Balaclava School	Education	Confirmed	N/A	0.02
Brockville School	Education	Confirmed	N/A	0.04
Ravensbourne School	Education	Confirmed	N/A	0.02
Tainui School	Education	Confirmed	N/A	0.02
Dunstan Hospital	Hospitals (without Surgery)	Confirmed	N/A	0.13
Dunedin Energy Centre	Other Manufacturing	Confirmed	159.26 (22.17)	N/A
University of Otago Arana College	Education	Confirmed	9.13 (1.27)	N/A
Kaikorai Valley School	Education	Confirmed	1.70 (0.24)	N/A
Bayfield High School	Education	Confirmed	1.38 (0.19)	N/A
King's High School	Education	Confirmed	1.12 (0.16)	N/A
Roxburgh Area School	Education	Confirmed	1.05 (0.15)	N/A
Dunedin North Intermediate	Education	Confirmed	0.88 (0.12)	N/A
Bathgate Park School	Education	Confirmed	0.80 (0.11)	N/A
East Otago High School	Education	Confirmed	0.71 (0.10)	N/A
George Street Normal School	Education	Confirmed	0.54 (0.08)	N/A
Silverstream Primary School	Education	Confirmed	0.49 (0.07)	N/A
Carisbrook School	Education	Confirmed	0.32 (0.04)	N/A
North East Valley Normal School	Education	Confirmed	0.29 (0.04)	N/A
Mornington School	Education	Confirmed	0.24 (0.03)	N/A
Palmerston School	Education	Confirmed	0.22 (0.03)	N/A
Elmgrove School	Education	Confirmed	0.19 (0.03)	N/A
Maori Hill School	Education	Confirmed	0.19 (0.03)	N/A
Macandrew Bay School	Education	Confirmed	0.15 (0.02)	N/A

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Port Chalmers School	**Education**	**Confirmed**	**0.15 (0.02)**	**N/A**
Abbotsford School	**Education**	**Confirmed**	**0.12 (0.02)**	**N/A**
East Taieri School	**Education**	**Confirmed**	**0.12 (0.02)**	**N/A**
Outram School	**Education**	**Confirmed**	**0.12 (0.02)**	**N/A**
Waikouaiti School	**Education**	**Confirmed**	**0.08 (0.01)**	**N/A**
Portobello School	**Education**	**Confirmed**	**0.05 (0.01)**	**N/A**
Graymont Makareao	Concrete/Lime	Unconfirmed	**132.66 (18.47)**	7.83
Keep it Clean Dunedin	Pet food & rendering	Unconfirmed	**54.54 (7.59)**	4.83
Fulton Hogan Cromwell Asphalt Plant	Concrete/Lime	Unconfirmed	**44.46 (6.19)**	9.78
Oceana Gold Macraes	Metals & Mining	Unconfirmed	**27.41 (3.81)**	3.86
Goodman Fielder Dunedin	Bakery	Unconfirmed	27.35 (3.81)	**1.15**
Keep it Clean Silverstream	Pet food & rendering	Unconfirmed	25.16 (3.50)	**4.75**
Fulton Hogan Logan Point Quarry	Concrete/Lime	Unconfirmed	**22.22 (3.09)**	4.89
Gregg's Coffee	Food & Beverage (with drying)	Unconfirmed	**18.94 (2.64)**	2.80
Lion Speights Brewery	Brewery	Unconfirmed	**11.47 (1.60)**	4.27
Preens Dry Cleaners Dunedin	Laundry	Unconfirmed	**8.20 (1.14)**	1.84
Fulton Hogan Dunedin Bitumen Plant	Concrete/Lime	Unconfirmed	**6.93 (0.97)**	2.68
Lion Emerson's Brewery	Brewery	Unconfirmed	**5.17 (0.72)**	0.88
Southern Lakes Laundries	Laundry	Unconfirmed	**2.75 (0.38)**	0.84
Mercy Hospital	Hospitals (with Surgery)	Unconfirmed	**1.60 (0.22)**	0.29

Twenty-nine sites (mostly schools) have already confirmed their fuel of choice, representing a demand for 179TJ (25,000t[30]) of biomass and 1TJ (0.2GWh) of electricity.

The potential fuel switching decisions associated with the remaining fourteen projects will be the focus of Section 7.2. We highlight in green the preferred fuel based on the MAC Optimal calculations outlined in Section 7.1.2.

[30] Wet tonnes (55% moisture content) and assuming a boiler efficiency of 80% (compared to coal at 78%).

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

7 Otago's decarbonisation pathways

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

The modelling presented below uses the detailed information from Sections 8 and 9 to develop different scenarios of the pace and magnitude of electricity and biomass uptake across the whole Otago region. We refer to each of these scenarios as 'decarbonisation pathways'.

7.1 Sources and assumptions

The modelling that sits behind the simulated pathways relies on a range of assumptions about the decisions individual organisations will make. Some of these relate to the individual characteristics of each process heat organisation in the Otago RETA, other estimates use the costs produced in Section 8 and 9 below.

Where possible we have used actual data for this analysis. The main sources of data include:

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

The emissions profiles and reduction opportunities of all the major sites have been covered off using these sources, covering the majority of emissions from the Otago RETA sites.

However, for sites where individual ETA data was not available, estimates based on other data available to EECA were made. For demand reduction and low temperature heat (<100°C) opportunities, if ETA data was unavailable, the information in Table 6 was used:

Table 6 – Assumptions regarding heat pump and demand reduction opportunities, where ETA information unavailable. Source: Lumen

Sector	Proportion of total heat demand < 100°C	Peak demand reduction (%)
Laundry	20%	5%
Pool heating	100%	12%
Meat processing	100%	26%
Pet food & rendering	5%	5%
Concrete/Lime	0%	3%
Food & beverage	100%	9%
Food & beverage (with drying)	32%	13%
Buildings	100%	13%
Hospitals (with surgery)	85%	14%
Hospitals (without surgery)	100%	14%
Education	100%	11%
Bakery	20%	12%

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

- Existing fossil fuel boilers are estimated to be 78% efficient.
- Biomass boilers are estimated to be 80% efficient.
- Electric Boilers are estimated to be 99% efficient.
- Capital costs for new boilers were derived from specific individual ETAs where available, or derived from wider ETA data where unavailable.
- Cost estimates for biomass have followed a path of $15/GJ ($110/t) for smaller volumes and $17/GJ ($122/t) for a large user. This reflects the supply curves illustrated in Section 7.7, which include the cost of delivery to a central biomass hub at Milton. To reflect the price to the end user, we also add costs associated with processing (for pellet manufacture) and secondary transport to a process heat user's site, as well as an indicative $3/GJ margin for organisations who facilitate the biomass chipping, storage and transport. The resulting cost used for delivered biomass, that includes all these components, is $23/GJ for smaller volumes and $25/GJ for a large user. This translates into $400/t and $433/t (respectively) for biomass processed into pellets.
- A conservative view of electricity upgrade costs required for each site has been incorporated as per Section 8.
- Variable electricity costs have used the central pathway from Section 9.2, along with estimates for distribution and transmission network prices discussed in that section. In some cases, we have substituted currently available retail market pricing[31] – targeted at process heat users in the South Island - for the near-term prices from Section 9.2.

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

- Demand reduction or efficiency projects are assumed to proceed, and to proceed first, so boiler sizing decisions are based off the post-efficiency/demand reduction requirements[32].
- If a site only demands hot water at less than 100°C, there is the potential to replace the entire boiler load with heat pumps (depending on opportunities for heat recovery on site). If a site contains both <100°C water and >100°C heat requirements, a mixed approach may be adopted, using heat pumps for the hot water demands and a boiler conversion or replacement for higher temperature needs.

7.1.1 Calculating marginal abatement costs

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

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

[32] As a result, the total boiler demand from sites post-fuel switching decisions is lower than the demand implied from the Regional Heat Demand Database.

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

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

MACs are calculated as:

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

The project costs included in the calculation include all capital, operating and fuel costs, but must not include the future estimated (Scope 1) costs of surrendering emissions units ('New Zealand Units', or NZUs) to the New Zealand Emissions Trading Scheme, as this is implied by the MAC[33].

Riverbank Substation, Otago, New Zealand. Credit – Aurora Energy.

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

7.1.2 Using MAC values to support investment decision-making

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

- **Fuel choice –** If there is more than one option available (i.e. biomass or electricity), the MAC also gives a relative ranking of the options expressed in terms of their marginal abatement cost. As stated above, the MAC value effectively provides a 'cost of carbon reduction' expressed in $/tCO$_2$e. A high MAC value suggests that project's cost of reducing a tonne of carbon dioxide is higher than a project with a low MAC value.
- **Investment timing –** Having determined the option with the lowest MAC, it then can be used as an indication of the best time to invest in decarbonisation by comparing it with likely carbon prices. Ultimately, carbon prices flow through to the fossil fuels used by the RETA organisations via the price of the fuels they use. If the national carbon price is expected to be higher than the MAC value (the cost of carbon reduction), then the organisation will have lower costs in the future by investing in decarbonisation and reducing its exposure to future carbon prices.

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

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

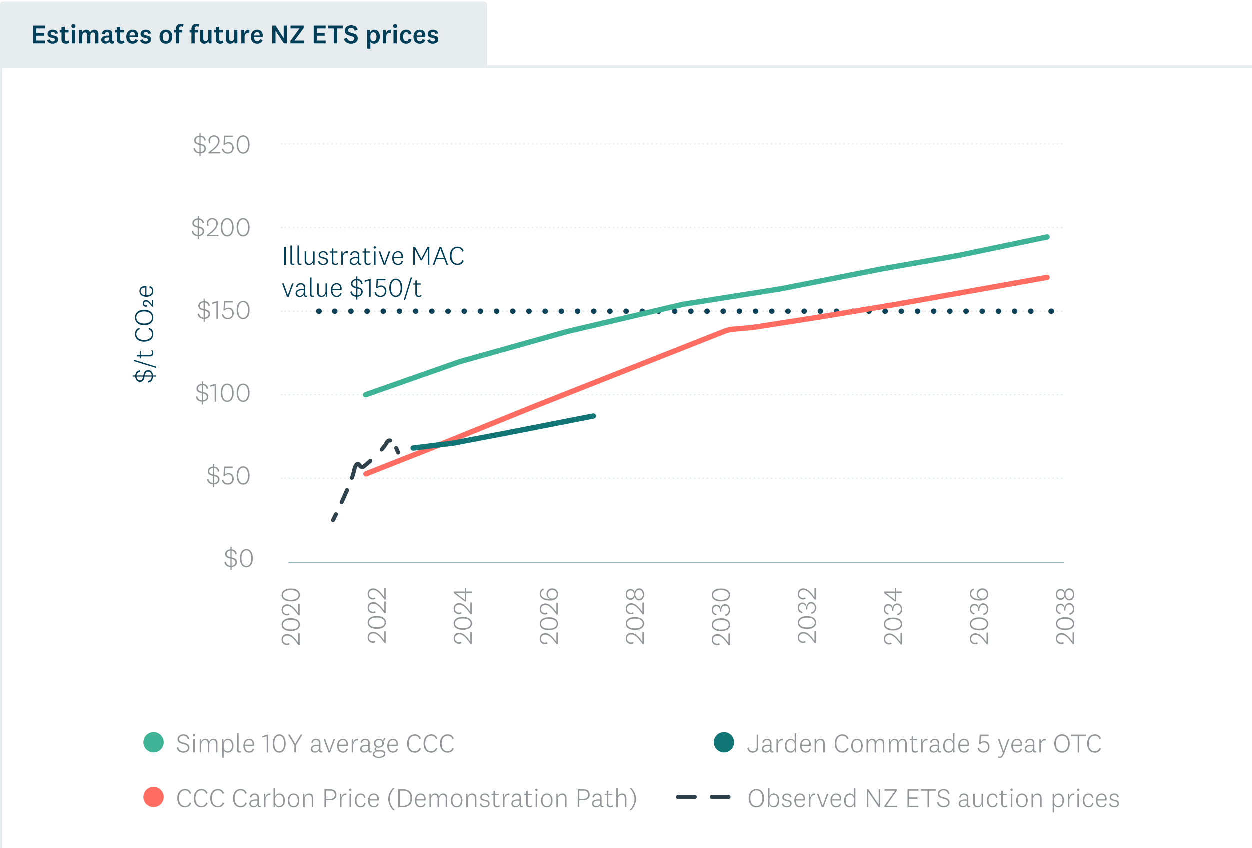
If the carbon price was expected to rise, then the investment would be more attractive than if only today's price of carbon was used. The challenge for many organisations is how to form a view on the carbon price (and thus its impact on the business) *in the future*[34], should it continue to consume fossil fuels. Unfortunately, there are few publicly available forecasts of carbon prices through which a process heat user can get confidence that carbon prices will reach a level which makes the investment economic. Even if these forecasts were available, it is entirely understandable that an investor might 'wait and see' if the increases materialise, before committing investment.

One view on future carbon prices is the Climate Change Commission's (CCC's) carbon price pathway from its 'Demonstration Path'[35] (represented as the red solid line in Figure 16). Technically, this is not a 'forecast'; rather, it is the series of modelled carbon prices (to 2050) which is consistent with New Zealand meeting its aspirations around carbon reduction. Whether or not carbon prices actually follow that pathway depends largely on whether Government policies and resulting decisions by consumers and businesses meet the 'emissions budgets' recommended by the CCC.

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

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

Figure 16 – Future views of carbon prices



Recognising that it is the carbon prices over the lifetime of the investment that represent the carbon costs that the organisation will face, we have used the 10-year future average of the CCC's Demonstration Path. This is the light green solid line in Figure 16.

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

We have also included one broker's clearing prices of NZU contracts being traded up to five years in the future – this offers another view of the market's expectation of carbon prices, as at March 2023[36]. It will likely include the effect of the failed NZ ETS auctions that took place in March and June.

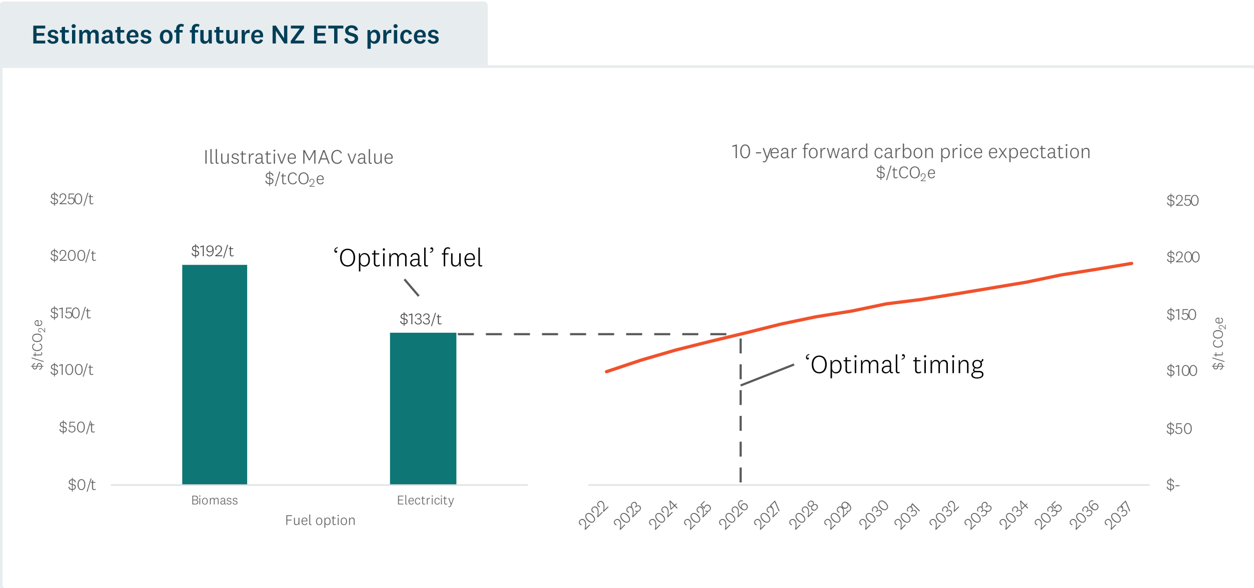
Different future views on carbon prices, and different ways of using those views, could have quite different impacts on the timing of decarbonisation projects proceeding. Assuming that the CCC Demonstration Path is a good forecast of carbon prices, Figure 16 shows that a project with a $150/t MAC value would not be committed until 2033 if the decision maker used the current carbon price to trigger the decision, but would proceed earlier (in 2028) if they used the simple average of the next 10 years of carbon prices implied by the CCC Demonstration Path.

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

For this report, we have chosen to use the 10-year forward average of the CCC's Demonstration Path to determine the investment timing, as we believe this is a better reflection of the actual financial impact of *future* carbon prices on a long-term investment than just using the solid red line in Figure 16[37].

The overall framework for how we use MAC values to create the MAC Optimal pathway below is shown in Figure 17.

Figure 17 – Illustration of how marginal abatement costs are used to determine optimal decision making



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

7.1.3 The impact of boiler efficiency on the cost of heat

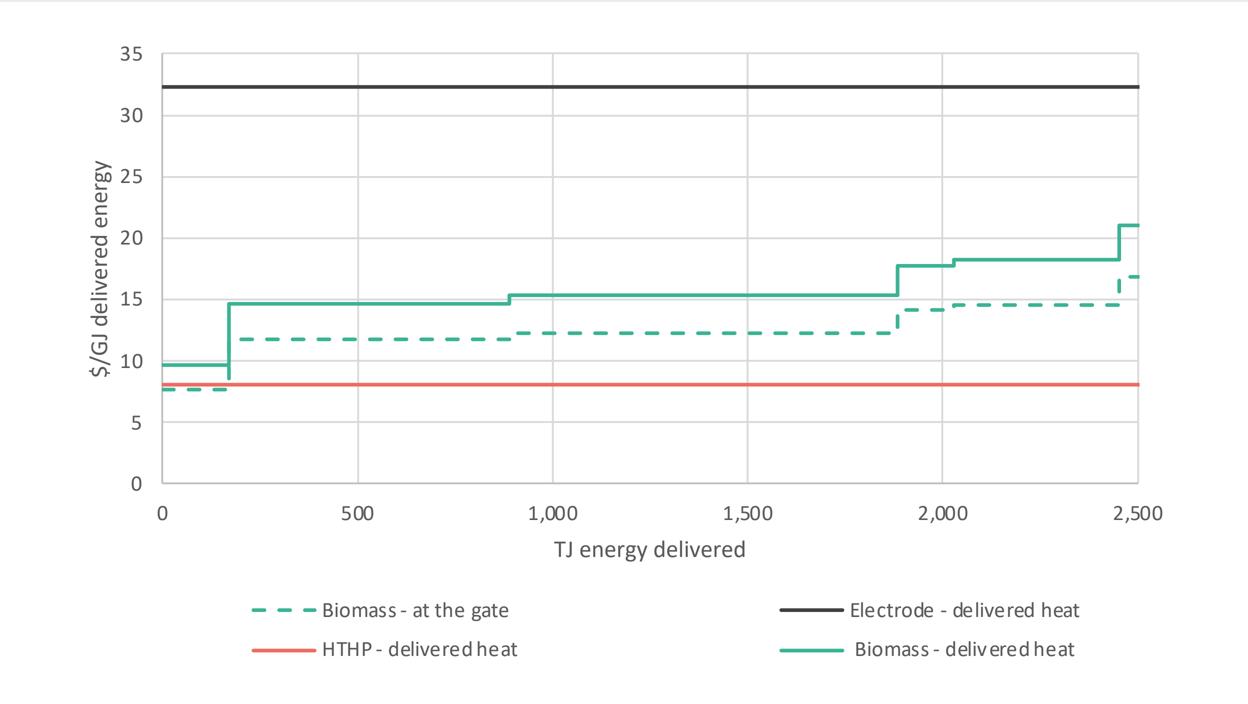
The MAC analysis implicitly trades off all the costs – capital, operating and fuel – to provide a single analysis of the lowest-cost fuel (from an emissions reduction perspective). This (necessarily) incorporates the different efficiencies of the boiler technologies chosen.

The delivered cost of biomass ('to the gate' of the site) cannot be directly compared with the delivered cost of electricity (or any other fuel) without accounting for the fact that biomass boilers have approximately 80% efficiency, whereas electrode boilers have close to 99% efficiency. On the same basis, heat pumps have coefficients of performance that are 4 or higher. The cost per unit of *heat* received by the process is therefore different from the cost per unit of the energy delivered to site.

In Figure 18, we illustrate the difference between these cost concepts using the bioenergy supply curve from Section 8.7 (for a biomass decision) and the electricity price path from Section 9.2 (for an electrode boiler or heat pump decision). Note that these are only the variable costs of the fuel, and do not incorporate the fixed costs associated with different investment decisions (which are considered with the MAC calculation). The biomass price does not account for any margin that suppliers may seek on the various bioenergy resources, which we expect would add $3/GJ to the biomass figure.

Figure 18 – Comparison of the variable costs of biomass and electricity from a delivered heat perspective. Sources: Ahikā /Margules Groome, EnergyLink, EECA.

Comparison of delivered heat prices
$/GJ, 2028-2032



7.1.4 Resulting MAC values for RETA projects

The range of marginal abatement costs for Otago RETA projects are illustrated in Figure 19 below. Individual MACs have been calculated for each site's demand reduction and heat pump projects, as well as the optimal choice of fuel for boilers. These charts include all 79 confirmed and unconfirmed projects.

Figure 19 – Number of projects by range of MAC value. Source: EECA

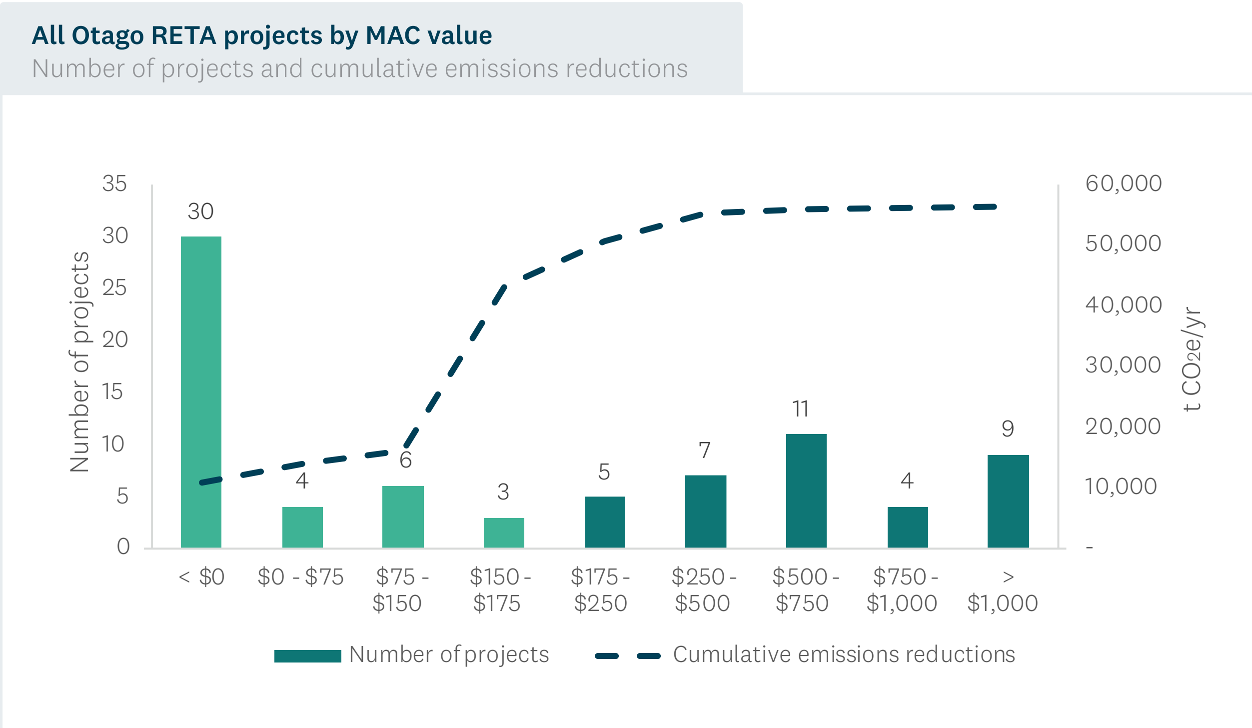
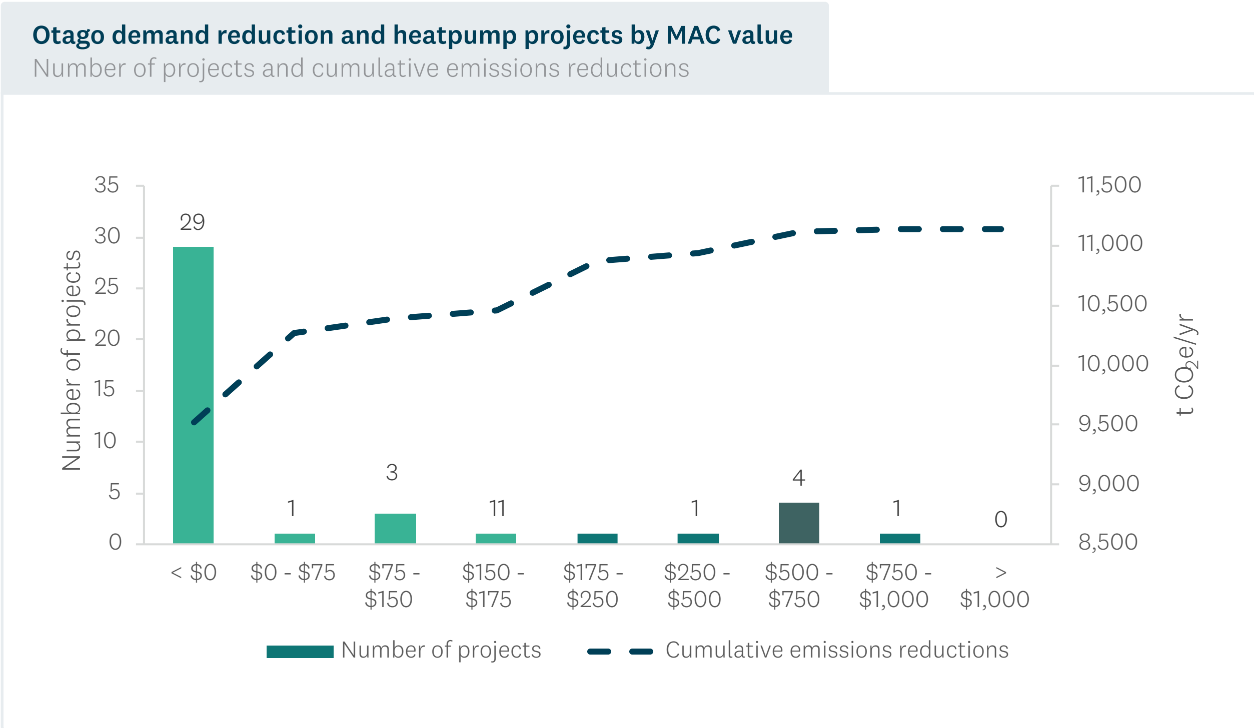


Figure 19 shows (highlighted in light green) 43 out of a total of 79 Otago projects that have MAC values less than \$175/t CO_2e. These projects would have a positive net present value (NPV) for the RETA organisations at some point in the period to 2037, if NZ ETS prices rose in line with the Climate Change Commission's Demonstration Path carbon price projections. The figure also shows that these 43 projects would deliver 77% (43,000tCO_2e) of the total emissions reductions from all RETA projects.

Thirty projects, delivering 19% of the total RETA emissions reductions, would be economic at today's carbon prices.

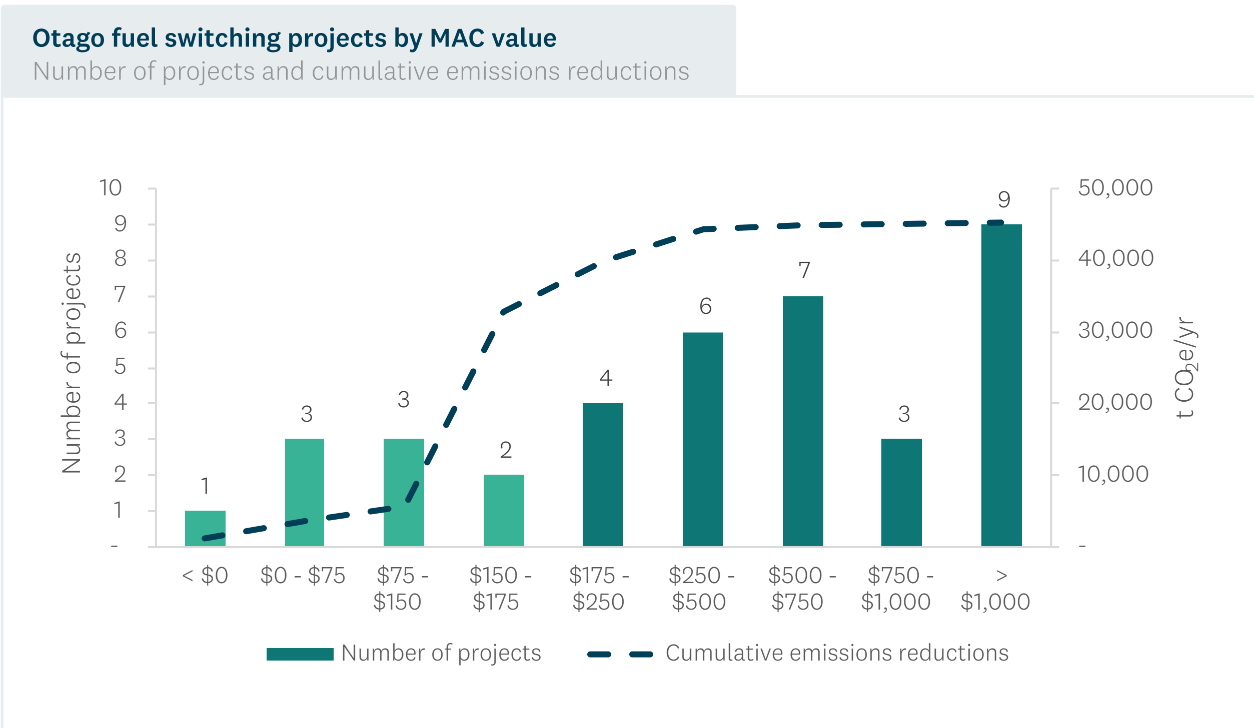
Figure 20 shows that 34 of the 43 lower-MAC economic projects are demand reduction and heat pump projects, delivering 10,500tCO_2e of emissions reductions.

Figure 20 – RETA demand reduction and heat pump projects by MAC value. Source: EECA



Fuel switching projects in Otago have higher MAC costs (Figure 21) reflecting the various combination of site-specific factors, such as the lumpy nature of potential electricity upgrade costs as calculated in Section 9 (where relevant); the operating profile over the year; and the overall utilisation of the boiler capacity. Notwithstanding that, five of these fuel switching projects are economic within the period, delivering 32,500tCO_2e of emissions reductions – 54% of the total RETA process heat emissions.

Figure 21 – RETA fuel switching projects by MAC value. Source: EECA

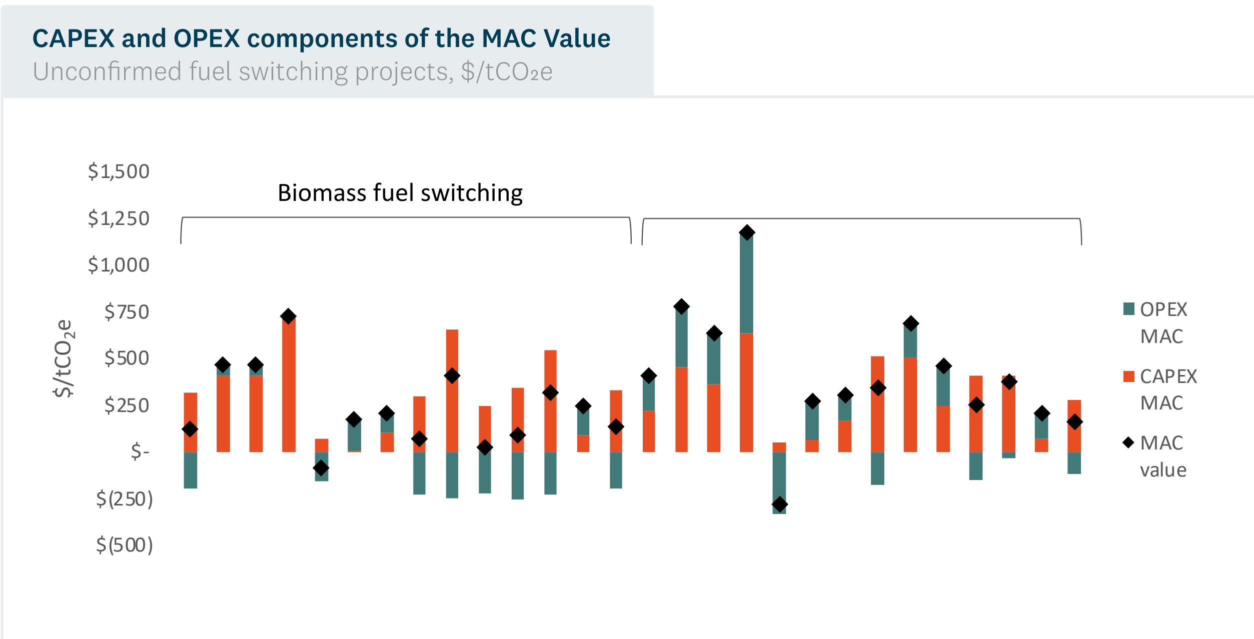


7.1.5 What drives Otago's MAC values?

Particularly for projects that have higher MAC values, there could be a range of ways cost reductions could be achieved to make the remaining projects more viable over the term of the RETA: for example, securing access to lower cost biomass resources, enabling plant flexibility to reduce the cost of electricity connections and/or electricity consumption, or access to targeted co-funding.

In order to better understand what components of a project's overall costs is driving the MAC values for Otago's RETA sites, Figure 22 illustrates the MAC values for each of the 14 unconfirmed fuel switching projects, where the MAC value is separated between the project's up-front capital costs (CAPEX) and operating costs or benefits (OPEX).

Figure 22 – CAPEX and OPEX MAC values for unconfirmed fuel switching projects. Source: Lumen



Queenstown, Otago, New Zealand. Credit – Aurora Energy.

Generally, across these Otago RETA projects, the capital component of the MAC value is much higher for biomass projects than electricity projects. This is due to the higher cost (per MW) of biomass boilers compared to electrode boilers – even allowing for the capital cost of connecting the electrode boilers to the network (see Section 9). However, the operating expense component of Otago electricity MAC values tends to be higher than biomass, resulting from the net result of three effects:

- Electrode boilers are 25% more efficient than biomass boilers, thus reduce more fossil fuel consumption per MW than biomass boilers; but
- Retail electricity costs are higher (per unit of energy) than biomass.
- Electrode boilers also face fixed network access charges[38] (see Section 9.2.4), which biomass boilers do not.
- A number of the Otago RETA fuel switching sites have low capacity utilisation (relative to other regions)[39], hence the fixed network costs are spread across a lower energy demand and thus emissions reduction quantity.

Note that the operating component of the MAC value is the net effect of the reduction in fossil fuel cost, and the cost of procuring the biomass or electricity. As shown in Figure 22, there are some situations – particularly where diesel or LPG is being used – where the net OPEX effect can be negative, because the low emissions fuel is overall cheaper than the fossil fuel, even without accounting for the impact of carbon emissions.

The net effect of the CAPEX and OPEX components, shown in Figure 22, is that switching to an electrode boiler in Otago usually has a higher MAC value than switching to a biomass boiler. This is not always the case, as will be illustrated in our pathways below. We also reinforce that the relativity of biomass and electricity MAC values in Otago is based on the regionally-specific assumptions this report has used as described above. It is not a general commentary on the relative economics of biomass versus electricity.

As will be reinforced in both Section 8 and Section 9, the costs used in our MAC value calculations could be improved on in a range of ways – for example, using flexibility to reduce the impacts on electricity networks (and therefore network charges) or accepting a lower level of security of supply. We also consider the impact of co-funding, amongst other scenarios and sensitivities, in Section 7.4.

[38] In EECA's modelling, based on the results of Section 9, the costs of electricity are split approximately equally between retail electricity and network charges.

[39] Otago had a number of sites where the capacity utilisation over the year was less than 20%. Our analysis assumed that network charges were (partly or completely) based on the maximum demand from the site. As explained above, a MAC value is essentially cost divided by emissions reductions; hence these low utilisation sites end up with a lower denominator than a high utilisation site, even if it had an identical maximum demand and thus faced exactly the same network charges.

7.2 Indicative Otago pathways

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

a) Boiler conversions involving facilities owned by the Ministry of Education, Ministry of Health or the Department of Corrections are all assumed to occur by the end of 2025, consistent with the Carbon Neutral Government Programme[40].

b) All RETA decarbonisation projects are executed by 2037 in line with the National Policy Statement for Greenhouse Gases from Industrial Process Heat (NPS) that came into effect in July 2023, which prohibits greenhouse gas emissions from existing medium temperature (<300°C) coal boilers after 2036[41]. This means that any projects that are still not 'economic' using our MAC criteria (illustrated in Figure 17) by 2036, are assumed to be executed in 2036. We also apply this assumption to LPG and diesel boilers, on the expectation that Government's desire to phase out coal boilers reflects a wider desire to largely eliminate process heat emissions.

The pathways were then developed as follows:

Pathway name	Description
Biomass Centric	All unconfirmed site fuel switching decisions proceed with biomass at the timing indicated in the organisation's ETA pathway. If not indicated, timing is set at 2036.
Electricity Centric	All unconfirmed fuel switching decisions with electricity as the sole fuel at the timing indicated in the organisation's ETA pathway. If not indicated, timing is set at 2036.
BAU Combined	All unconfirmed fuel switching decisions (i.e. biomass or electricity) are determined by the lowest MAC value for each project; timing of commissioning as indicated in the organisation's ETA pathway. If not indicated, timing is set at 2036.
Linear	Each site switches to the fuel with the lowest MAC value for that site; projects ordered and timed to achieve a relatively constant annual level of emissions reduction and growth in electricity/biomass consumption (within reason)[4].
MAC Optimal	Each site switches its boiler to the fuel with the lowest MAC value for that site. Each project is timed to be commissioned in the first year when its optimal MAC value first drops below a ten-year rolling average of the Climate Change Commission's future carbon prices in their Demonstration Path.

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

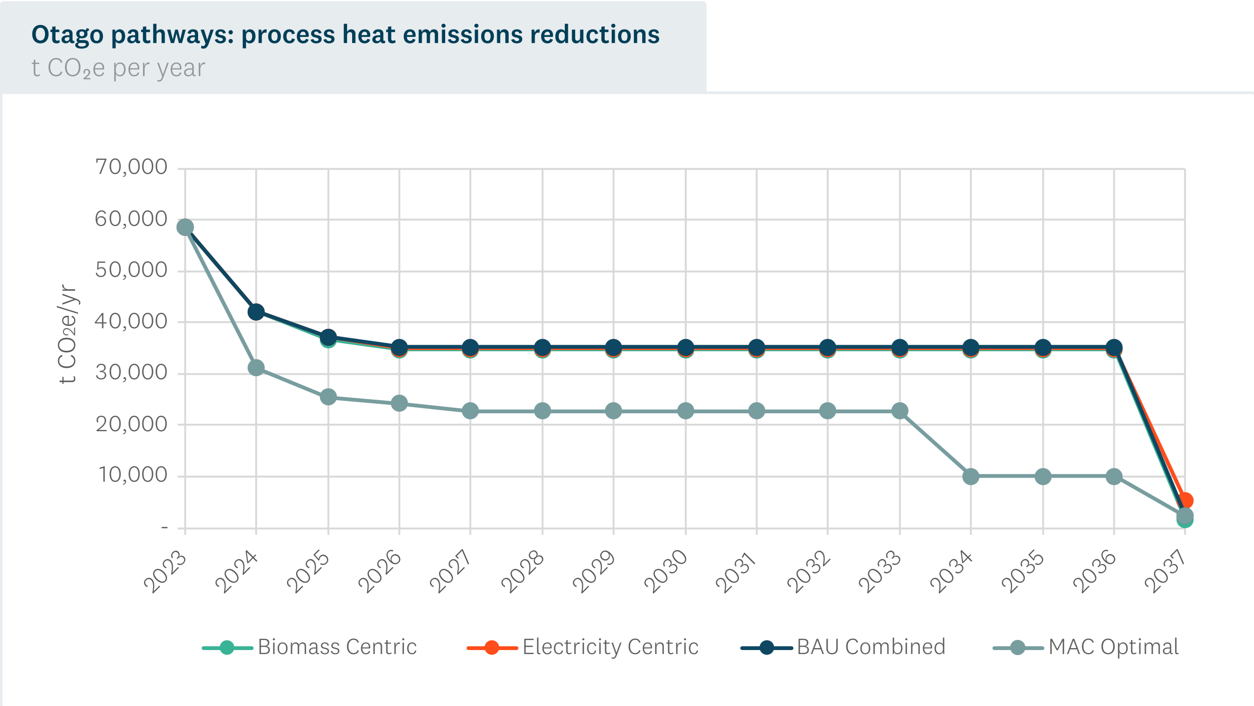
[41] See https://environment.govt.nz/acts-and-regulations/national-policy-statements/national-policy-statement-for-greenhouse-gas-emissions-from-industrial-process-heat/. The new National Environmental Standard which supports the NPS also places increased restrictions on process heat boilers burning fossil fuels other than coal. We assume that all RETA process heat fossil fuels will convert to a low emissions equivalent by 2037.

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

7.2.1 Pathway results

All pathways eliminate between 91% and 98%[43] of process heat emissions in the region (a reduction of between 53,000 to 57,000tCO_2e out of a total of 59,000tCO_2e), but at significantly different pace (Figure 23).

Figure 23 – Emissions reduction trajectories for different simulated pathways. Source: EECA



The Otago MAC Optimal path achieves the fastest emissions reductions, with over 50% of emissions reductions achieved by 2027. Under the fuel-centric and BAU pathways for Otago, most emissions reductions aren't achieved until they are effectively 'forced' in 2036. The cumulative difference between the MAC Optimal and the other pathways, is 196,000 tCO_2e – exclusively long-lived greenhouse gases – across the period 2022 to 2036.

Figure 24 breaks down the MAC Optimal pathway by the same components used in Figure 15. Nearly 30% of the emissions reductions result from confirmed biomass fuel switching projects. The pathway suggests that a further 38% will be achieved through further biomass fuel switching, with 23% from electricity. The majority of emissions reductions from electrification will be through the use of heat pumps.

[43] Residual emissions at the end of each pathway relate to Scope 2 emissions from the varying amounts of electricity consumption. As outlined earlier, electricity is modelled to have a Scope 2 emissions content of 50kg per MWh of electricity, assuming the electricity sector reaches a higher degree of renewables (and fewer fossil fuels) over the next 15 years.

Figure 24 – MAC Optimal pathway by technology used. Source: Lumen

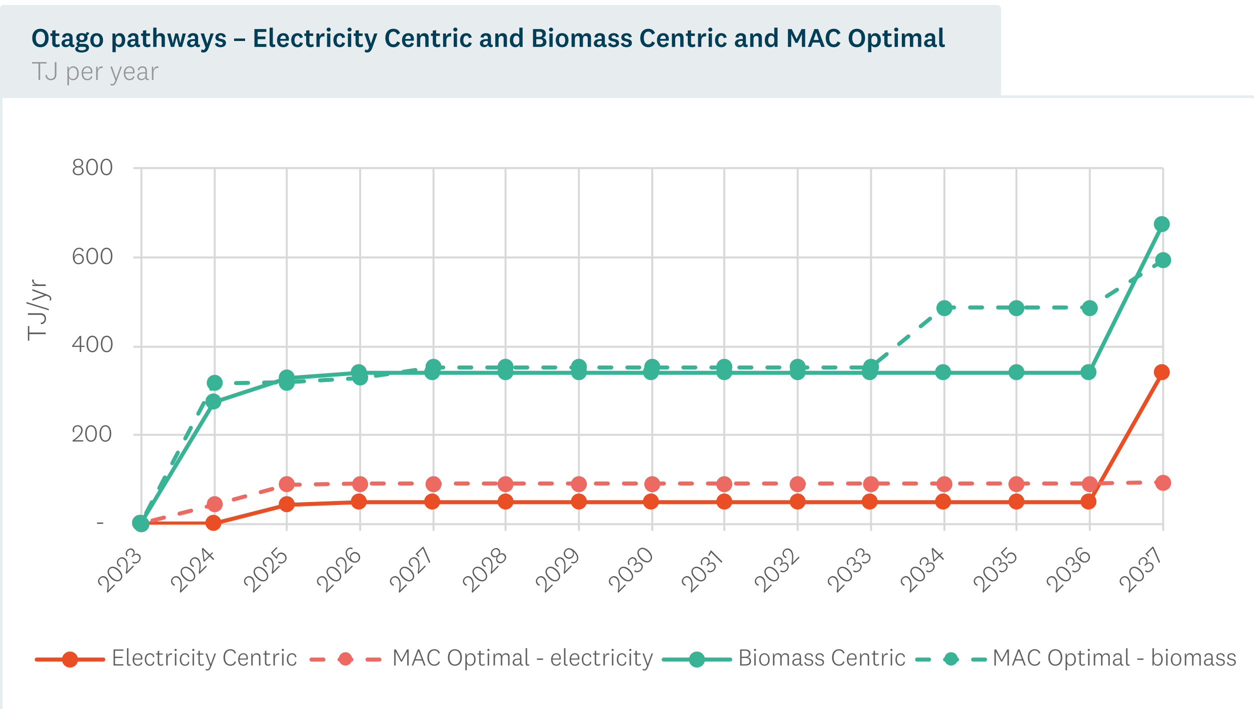
Optimal MAC

	Category	Status	Annual savings (t CO_2-e)	(%)	Remaining emissions
	Baseline Emissions				100% (58,710 t CO_2-e/yr)
Energy efficiency	Demand Reduction	Confirmed	-	0.0%	100%
Heat pump	Heat Pump	Confirmed	305	0.5%	99.5%
Biomass	Fuel Switching – Biomass	Confirmed	17,167	29.2%	70.2%
Electric	Fuel Switching – Electric	Confirmed	-	0.0%	70.2%
Energy efficiency	Demand Reduction	Unconfirmed	3,111	5.3%	64.9%
Heat pump	Heat Pump	Unconfirmed	7,724	13.2%	51.8%
Biomass	Fuel Switching – Biomass	Unconfirmed	22,335	38.0%	13.7%
Electric	Fuel Switching – Electric	Unconfirmed	5,783	9.9%	3.9%

7.3 Pathway implications for fuel usage

We can now compare the trajectory of demand for biomass and electricity arising from the various Otago pathways. Below we compare the growth in demand in the two fuel-centric pathways with the MAC Optimal pathway. As shown in Figure 25, the Biomass and Electricity Centric pathways understandably deliver the highest demands in 2036 for each fuel – 341TJ for electricity, and 675TJ for biomass[44]. The pathways that use MACs to determine fuel switching decisions result in a different set of fuel decisions, with around 86% of the energy needs supplied by biomass (with a consumption of 593TJ of delivered energy), and 14% of energy needs supplied by electricity (with 93TJ of delivered energy).

Figure 25 - Simulated demand for biomass and electricity under various RETA pathways. Source: EECA



[44] Recall that a number of projects are already confirmed as biomass. This is why under two Centric pathways, the resulting fuel consumptions are quite different.

The pathways illuminate two significant decisions in the use of biomass:

- The confirmed decision by the Dunedin Energy Centre to switch to biomass in 2024.
- The unconfirmed (and therefore modelled) decision by Graymont Makareao to switch to biomass in 2037.

The majority of the remaining decisions are made in 2036.

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

7.3.1 Implications for electricity demand

Figure 26 shows the growth in electricity demand in each of the pathways.

Figure 26 – Growth in electricity demand from fuel switching pathways (unconfirmed RETA sites). Source: EECA

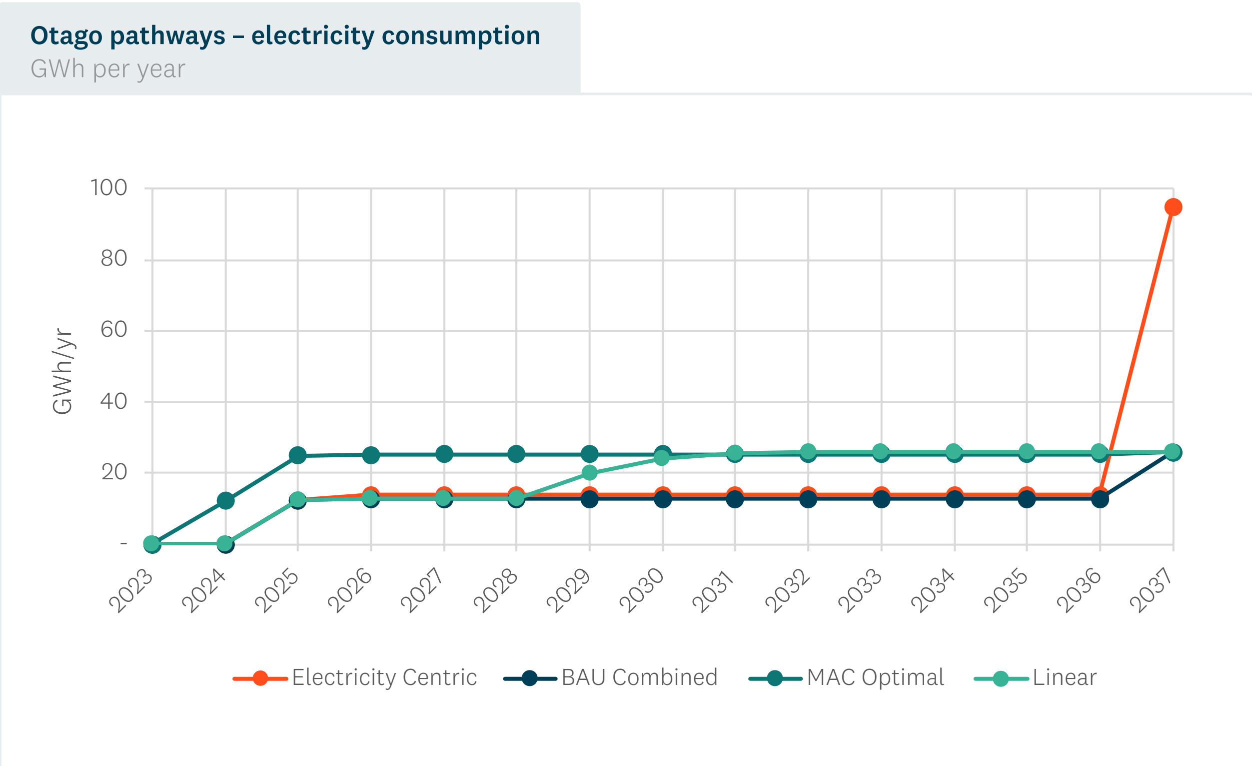
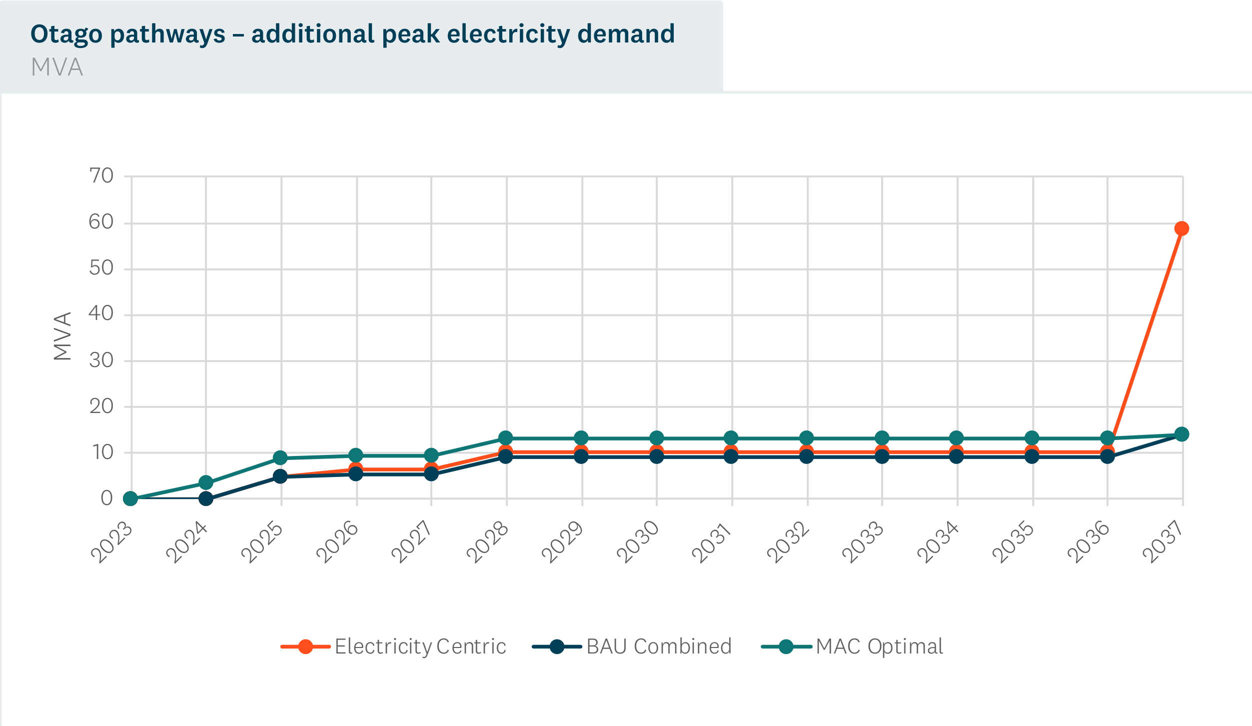


Figure 26 shows that the use of MACs to simulate decision making accelerates unconfirmed projects, particularly Keep it Clean which, in a fuel-centric world, would not be switched until 2036, whereas the MAC criteria see it convert to electricity in 2025.

Even in an Electricity Centric world, electricity consumption in Otago would only grow by around 5% compared today, although not until 2036. Under the MAC Optimal, Linear and BAU Combined worlds, electricity consumption would only grow by 1%. The vast majority of this growth would be observed in the next two years in a MAC Optimal pathway.

A more critical aspect of the process-heat driven growth – and timing of growth – in electricity demand is the impact it has on network planning. Networks will be more interested in the impact on potential peak demand than energy consumption. Figure 27 illustrates the potential increase in peak demand, for each pathway. This is determined by adding together the maximum demand from each boiler, without taking account of demand diversity (as outlined in Section 9.4).

Figure 27 - Potential peak demand growth under different pathways



The difference between the scenarios through time is relatively minor – ranging between 10MVA and 13MVA – until 2037 where the Electricity Centric pathway reaches much higher peak demand levels than all other pathways. Prior to that, the additional peak demand from the electrified boilers and heat pumps represents a 3%-5% increase in the combined networks' coincident peak demand. However, this relatively small percentage disguises the impact on particular parts of the network.

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

7.3.1.1 EDB analysis

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

Section 9.3 highlights that there can be material differences between adjacent networks in terms of unused capacity. These differences exist for a range of historical reasons. This can lead to quite different relative network upgrade costs for projects connection in each region. Table 7 shows how the connections potentially affect each EDB's network.

Table 7 – New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways. Source: EECA and Lumen.

EDB	Electricity Centric pathway		MAC Optimal pathway	
	Connection capacity (MW)	Connection cost ($M)	Connection capacity (MW)	Connection cost ($M)
Aurora (Dunedin)	32	$4.9	10	$1.0
Aurora (Central)	14	$3.6	4	$-
Aurora (Queenstown)	1	$0.1	0.2	$-
OtagoNet	12	$4.4	-	$-
Total	**59**	**$12.9**	**14.2**	**$1.0**

Table 7 shows that Aurora's Dunedin network will experience the largest increase in process heat-related electricity demand, irrespective of whether the Electricity Centric or MAC Optimal pathway results. The connection cost estimates suggest that between $1M to $13M will be spent connecting new process heat plant to the local networks, depending on the pathway.

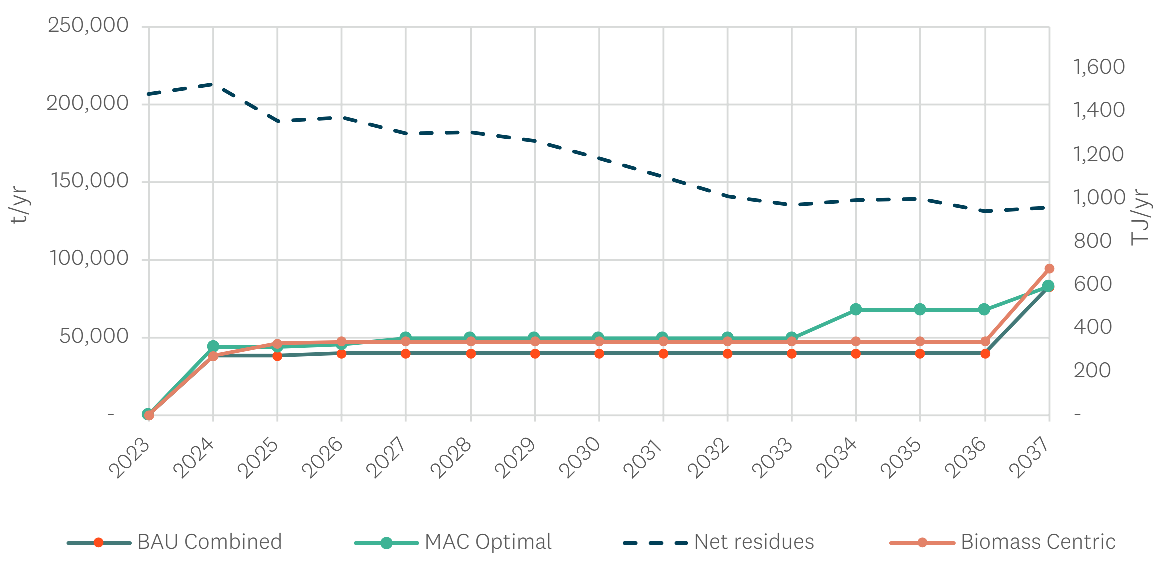
Note that the network upgrade costs presented in Table 7 may not necessarily reflect the connection costs paid by RETA organisations, as they may be shared between the EDB and the new process heat user. The degree of sharing ('capital contributions') depends on the policies of individual EDBs, as discussed further in Section 9.2.4.2.

7.3.2 Implications for biomass demand

Figure 28 shows the growth in biomass demand (in both tonnes and TJ per year) arising from each of the pathways. The MAC Optimal and BAU Combined pathways result in less than half the final demand from the Biomass Centric pathway.

Figure 28 – Growth in biomass demand from pathways. Source: EECA

Otago pathways – biomass and available residues
Tonnes (LHS) & TJ (RHS)



We can also see that the estimated volumes of unutilised harvesting and processor residues (after existing bioenergy demands are removed[45]) are more than sufficient to meet the biomass demand under all pathways. This is shown as the dashed line in Figure 28. Note that the assessment of these resources is based on a more conservative estimate of recoverable harvesting volumes, as outlined in Section 8.5.2.

The potential use of harvesting and processor residues for biomass projects in any of the pathways above is a significant commercial opportunity for organisations that could provide the sourcing, collecting, processing, storing and delivery to process heat users.

Based on EECA's analysis – explained in Section 8 in more detail – the cost of the underlying fibre alone could be between $50M and $80M over the next 15 years[46].

[45] See Section 8.6.

[46] Assuming an underlying cost of woody biomass out of the forest of $13.50/GJ, as outlined in Section 8.7.

7.4 Sensitivity analysis

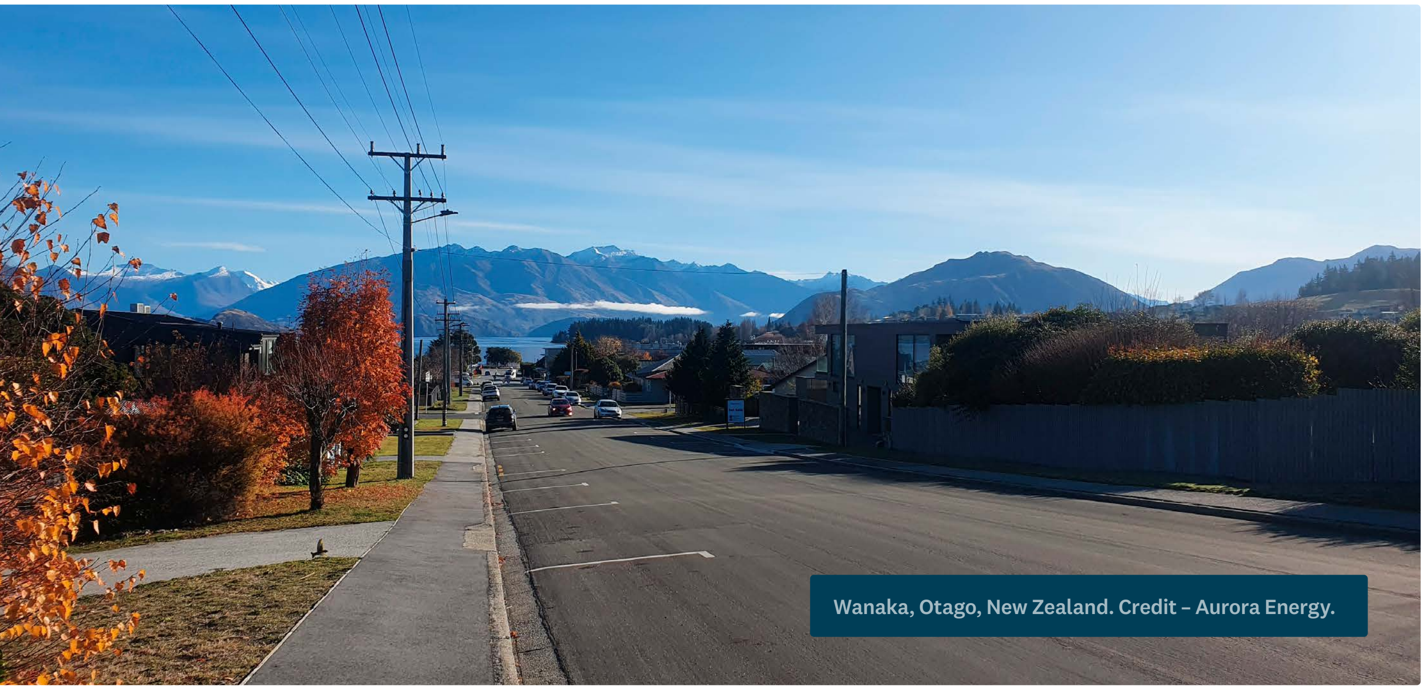
EECA acknowledges that there are a range of factors which determine each organisation's final decision on fuel switching. The net present value of a project (at the expected carbon price) is only one factor, albeit an important one for owners and shareholders. However, capital constraints, competing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

This report does not speculate on those factors. However, understanding how sensitive the fuel choice is to the commercial factors may go some way to providing confidence of the best decision, both in terms of fuel choice, and timing. This RETA report has outlined some of the uncertainties related to both up-front and ongoing fixed and variable costs, for example:

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

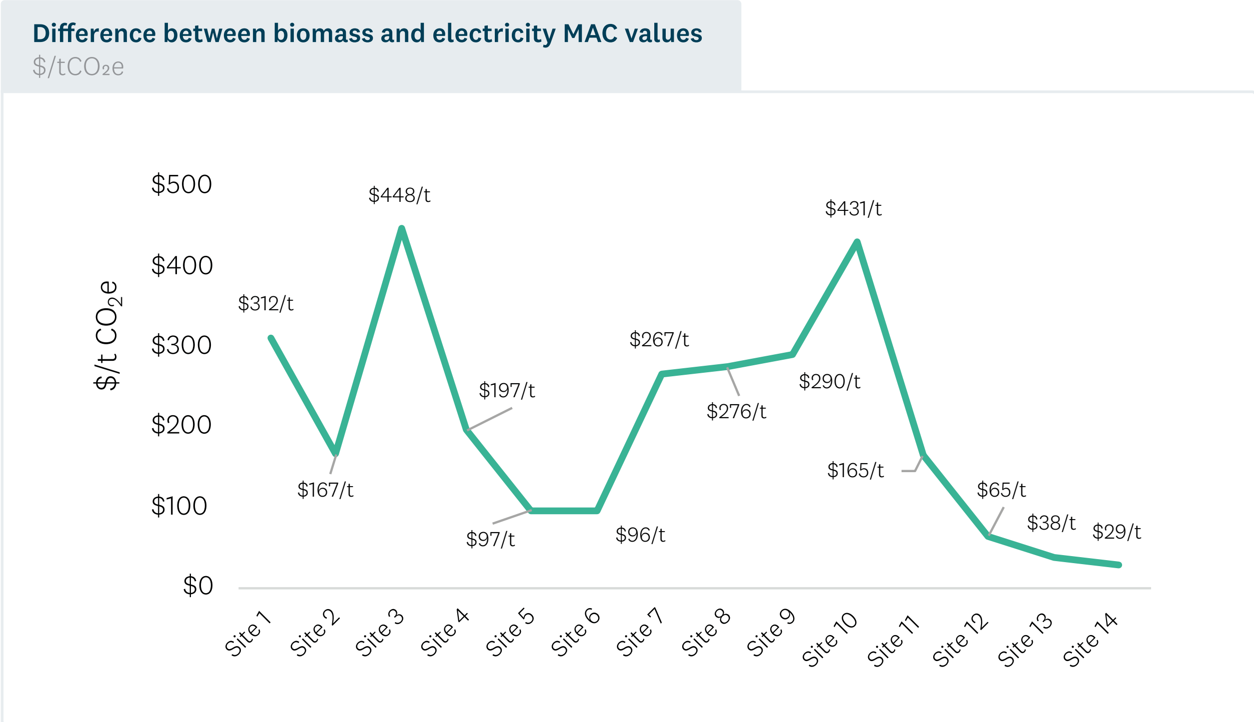
In terms of fuel switching, one way to consider how sensitive the fuel switching decision is to variability in underlying costs is to look at how close the MAC values for the competing fuels are.

For the 14 RETA sites where the fuel switching decision is still unconfirmed, and both electricity and biomass are being considered, Figure 29 shows that five of these projects have differences between electricity and biomass MAC values of less than \$100/t, with two under \$40/t.



Wanaka, Otago, New Zealand. Credit – Aurora Energy.

Figure 29 – Difference between electricity MAC value and biomass MAC value; sites that are considering both options. Source: EECA



It would take a considerable change in underlying costs to change the optimal fuel decisions for the remaining projects, but for these five, plausible deviations from EECA's input estimates used in this analysis could change the decision. To illustrate the sensitivity of these MAC values for the 14 projects in Figure 29:

- A 20% change in up-front capital costs (including network upgrade costs) for either electricity or biomass can change the MAC value of fuel by around $63/t CO_2e on average, and up to $143/t CO_2e for one project.
- A change the incremental[47] operating costs (including fuel procurement) of 20% could change the MAC value by $37/t CO_2e on average, and up to $108/t CO_2e for one project. A specific example of this is highlighted in Section 8.7, where the transport costs from a central biomass 'hub' to individual process heat users was discussed. Whilst most of the potential biomass users are located within 60km of the assumed hub[48], four potential customers are at least 100km away, and one is 210km away. We estimate this would add between 15%-23% to the cost of the biomass, if these process heat users chose to purchase biomass from the hub. In two cases, this would change the optimal fuel choice from biomass to electricity.

[47] This is not the same as saying that a 20% change in electricity price, or biomass price, will have this effect. As outlined above, the OPEX component of a MAC calculation is the difference between the cost of continuing to use coal, and the cost of switching to electricity or biomass. Here we are changing the magnitude of the difference, which would require a greater than 20% change in the cost of the fuels.

[48] As discussed in Section 8, we suggest this hub is located in Milton.

Hence it is plausible that these changes could alter the relativities of the two fuels, and therefore the fuel switching choice. Even if the fuel switching decision didn't change, the change in MAC could accelerate or delay the timing of the fuel switch, in the MAC Optimal pathway. We note that the sensitivities presented above only consider decisions to replace existing boilers with new boilers – this does not include the sensitivity of fuel switching decisions that could include the use of high temperature heat pumps. This will be included in future RETA reports.

These illustrative changes also highlight that, all things being equal, changes in the lifetime OPEX of a fuel switching investment has a similar impact on the MAC value as the upfront CAPEX. While the CAPEX component requires the greatest focus in terms of the funding and financing of the investment, cost of fuel over the 20-year lifetime of the decision is critical too.

Beyond up-front capital and ongoing fuel prices, there are a range of other factors which may change the MAC value and therefore the decisions made by process heat users. For example, a restriction in the availability of sustainable biomass may arise, meaning organisations who commit to decarbonisation late in the RETA period are only able to electrify.

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

- Amending the MAC Optimal pathway to include acceleration co-funding from the GIDI fund. GIDI co-funding has been applied to projects in a consistent manner.
- The use of Energylink's 'Low' price scenario, from Section 9.2.2.1, to determine the price of electricity.
- Amending the decision criteria for the timing of a decarbonisation investment, from when the average of the 10-year carbon price forecast exceeds the MAC, to when the current year carbon price exceeds the MAC (as discussed in Section 10.1.2).

Below we discuss these sensitivities.

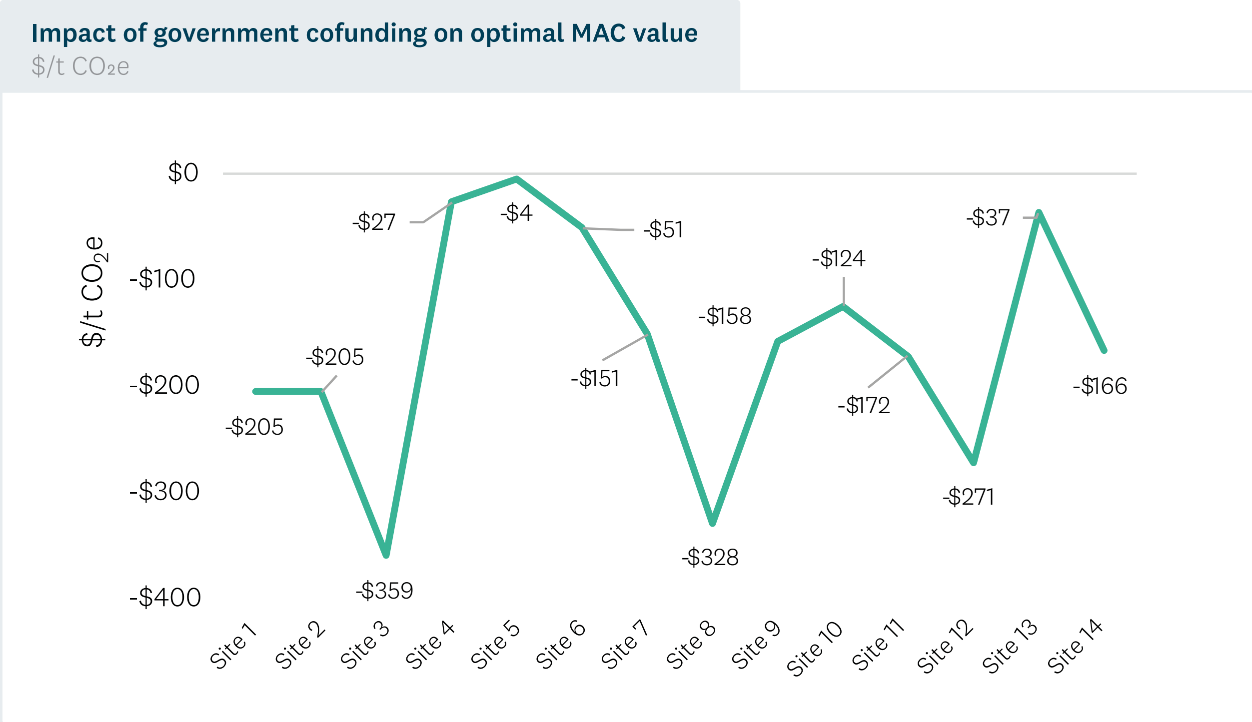
An additional model of optimal decisions was conducted using TIMES-NZ. TIMES-NZ is an optimisation model of the whole energy system (in this case, just the Otago region) and is thus able to optimise individual process heat user decisions based on available biomass and electricity supply and costs. This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

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

7.4.1 Acceleration co-funding

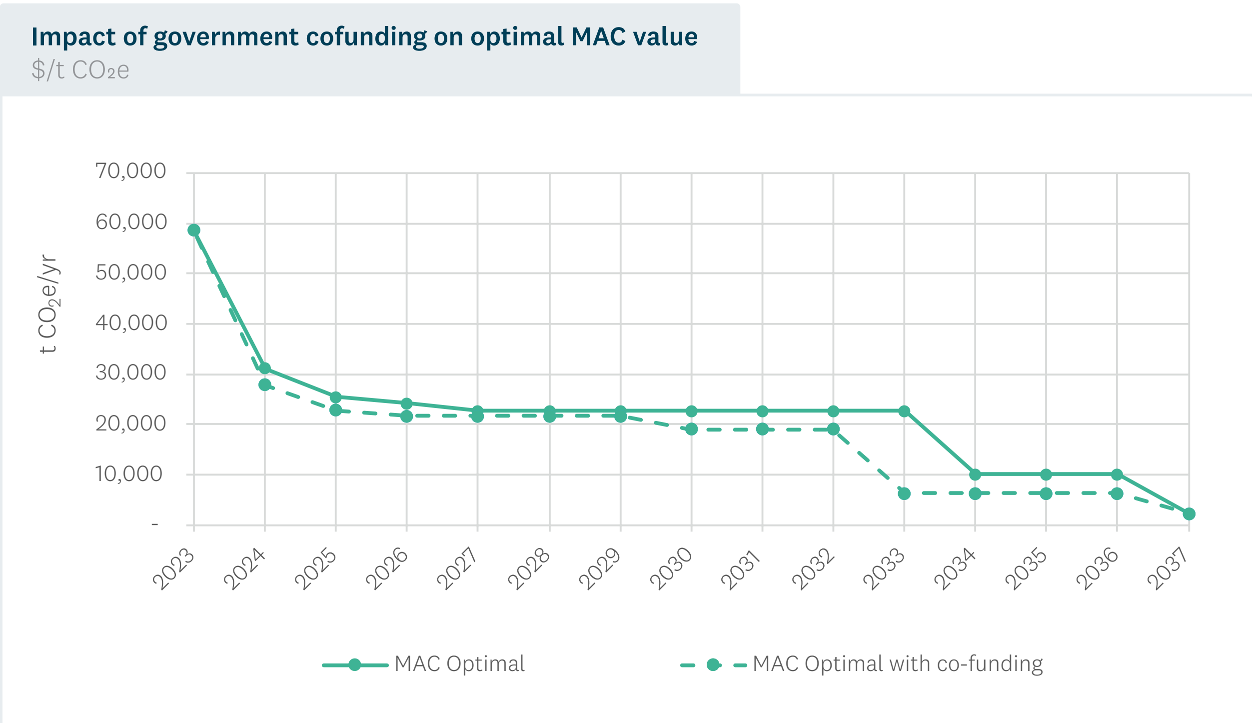
For the 14 fuel switching projects that are unconfirmed, the impact of a simulated government GIDI co-funding, applied in a consistent manner to each project, is to lower the MAC value. The impact of cofounding is different for each project, as shown in Figure 30.

Figure 30 – Impact of government co-funding on fuel switching MAC values. Source: EECA and Lumen.



While the co-funding changed the MAC value, it did not change the optimal fuel decision. It did, however, accelerate the timing of some projects, as the lower MAC value resulted in an earlier decision being optimal. This is illustrated in Figure 31.

Figure 31 – Range of MAC values and cumulative emissions reductions with co-funding – fuel switching only. Source: EECA



MACs are only one measure of how a process heat organisation will make a decision with respect to the timing of its decarbonisation investment – the degree to which, over the long term, the investment will lead to a better outcome for the business. But the investments contemplated in Figure 31 involve significant up-front funding requirements. While many businesses have access to the commercial financing products needed to fund decarbonisation projects, most have constraints on the amount they can borrow from these sources, leading to competition for limited pools of internal capital. Decarbonisation projects are often deprioritised due to less attractive internal rates of return than other projects, or because decarbonisation is considered a lower priority than, for example regulatory compliance, or investing in expanded production.

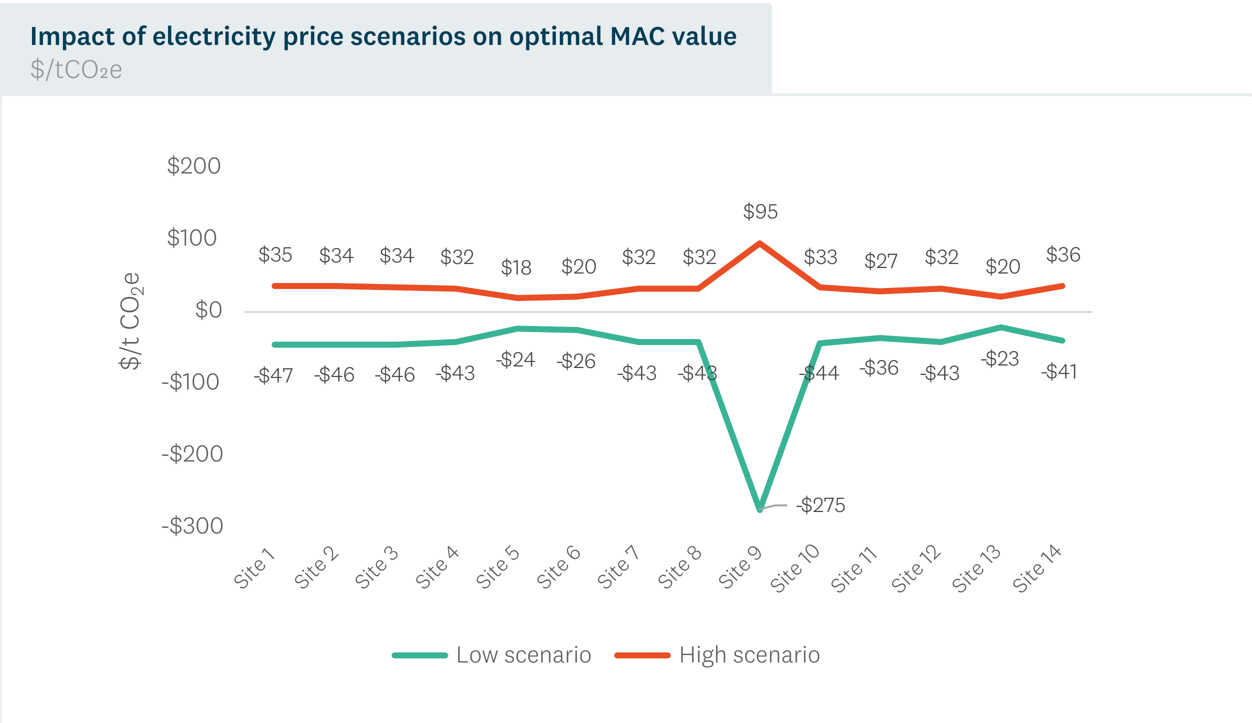
Hence the impact of co-funding on MACs alone only tells part of the story. The presence of decarbonisation co-funding may also overcome these wider constraints, even if it has a relatively small effect on the project's economics. Even projects that appear to be economically efficient may not occur (or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

7.4.2 Lower electricity prices

As discussed in Section 9.2.2.1, there are a range of factors that could lead to electricity prices that are materially different to the 'central' scenario used for the analysis in this chapter. As discussed in that section, we presented a 'high' and 'low' price scenario.

Using the 'high' and 'low' scenario in the MAC calculations led to modest changes – and one very significant change – in MAC values, as shown in Figure 32.

Figure 32 – Impact of Energylink's electricity price 'low scenario' and 'high scenario' on MAC values



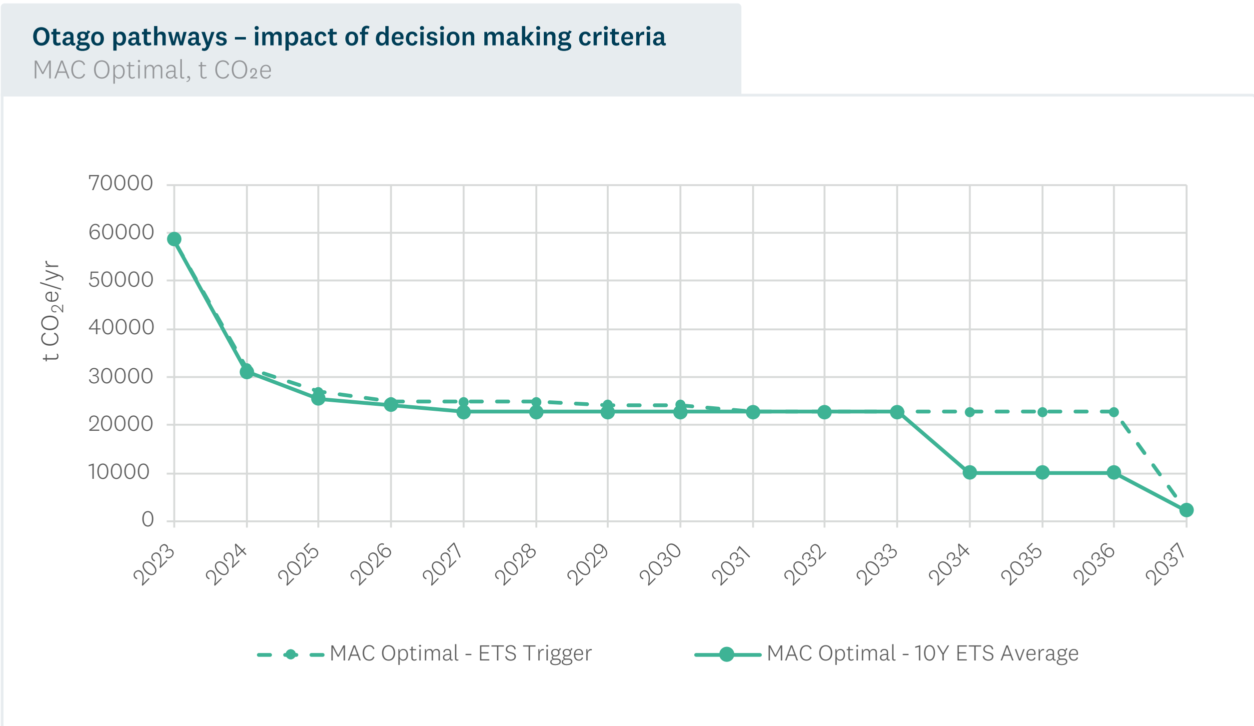
The low scenario closed the gap between biomass and electricity for a lot of unconfirmed projects and led to one change in fuel choice, from biomass to electricity.

Neither electricity pricing scenario was material enough to change the timing or optimal fuel for each project. The relatively small effect is largely due to the use of a market-based retail tariff that was lower than EnergyLink's price forecast, for number of projects, in the first 10 years of the project. Hence a sensitivity analysis that used a different EnergyLink scenario only changed the second 10-year period of the MAC calculation. The impact of this latter period on the MAC value will be significantly muted by present-value discounting.

7.4.3 Amending the decision criteria for investment timing

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

Figure 33 – Comparing MAC-based decision making criteria



Most notably, the 'current year' criterium leads to a three-year delay in one of the larger fuel switching decisions (to biomass). This is a result of the CCC's carbon price scenario increasing through time; hence a forward-looking 10-year average will always be higher than the present-day carbon price and will thus trigger investments earlier (all other things being equal).

Central Otago, New Zealand. Credit – Aurora Energy.

8 Bioenergy in Otago

8.1 Approach to bioenergy assessment

This section considers the availability and potential cost of wood resources in the Otago region as a potential source of bioenergy for process heat fuel switching. While there are other sources of biomass (e.g. landfills), the focus is on major sources that could collectively provide up to 194,070t per year – which would be the demand should all RETA sites[49] elect to switch to biomass for process heat.

Factors that need to be considered when determining the sustainability of biomass from forestry are outlined. The approach is then to:

- Consider the total availability of biomass from forestry in the region, including those sources that are not currently being recovered from, for example, in-forest harvesting operations, to obtain a theoretical potential for locally sourced biomass for process heat. We adopt both a top-down and bottom-up (via interviews with forest owners) approach to this. The bottom-up analysis provides an assessment of existing usage of woody biomass for bioenergy, as well as of how the wood is expected to flow through the supply chain – via processors to domestic markets, or export markets.
- Expert judgement is applied to allow for a more realistic assessment of the volumes of harvesting residues that can be practically recovered.
- Highlight the existing domestic and international markets for the harvested wood, either for timber products or existing demand for bioenergy (e.g. firewood) that will likely constrain the ability to divert wood to bioenergy for process heat in the near-term.
- Consider what this analysis implies for the potential cost of delivering different types of biomass to process heat users.
- Overlay the MAC Optimal and Biomass Centric scenarios of process heat demand for biomass from RETA fuel switching decisions, to ascertain whether this demand could be met from near-term available sources, noting that the supply of bioenergy will evolve through time.

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

[49] Other than those which have already confirmed, at the time of this report, they are choosing electrode boilers.

Only biomass sources within the Otago region are considered. We note that some forestry resources close to the border between Otago and Mid-South Canterbury were included in the Mid-South Canterbury RETA analysis[50], while the Clutha district's forest resources are included here, despite Clutha process heat users coming under the boundaries of the Mid-South Canterbury RETA.

More generally, neighbouring regions could also source biomass from the forests that are included in the Otago RETA assessment, where transport costs and logistics make this practical[51]. The potential for inter-regional trade in biomass will be considered when all South Island RETA reports are complete, and the island as a whole can be analysed.

We are aware that process heat is not the only future user of bioenergy competing with existing markets for wood. International demand for bioenergy may increase in the future, leading to countries trading in biomass. Further, and as outlined in New Zealand's emissions reduction plan (ERP), biofuels are a potential low-emission alternative to existing oil-derived transport fuels, and the plan included an action to implement a sustainable biofuels obligation[52]. This requires further analysis, as EECA does not currently have reliable estimates for the likely local demand for biofuels.

[50] Available at https://www.eeca.govt.nz/co-funding/regional-decarbonisation/mid-south-canterbury-regional-energy-transition-accelerator/

[51] Reinforcing this, we note that the forest resources for the Clutha district were included in the Otago assessment, while a small number of process heat users in the Clutha district were accounted for in the Southland RETA report.

[52] We note though that although the first Emissions Reduction Plan included a sustainable biofuels obligation, this has been indefinitely paused - see https://www.stuff.co.nz/environment/climate-news/131176812/prime-minister-chris-hipkins-opens-a-hole-in-the-carbon-budget.

8.2 The sustainability of biomass for bioenergy

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

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

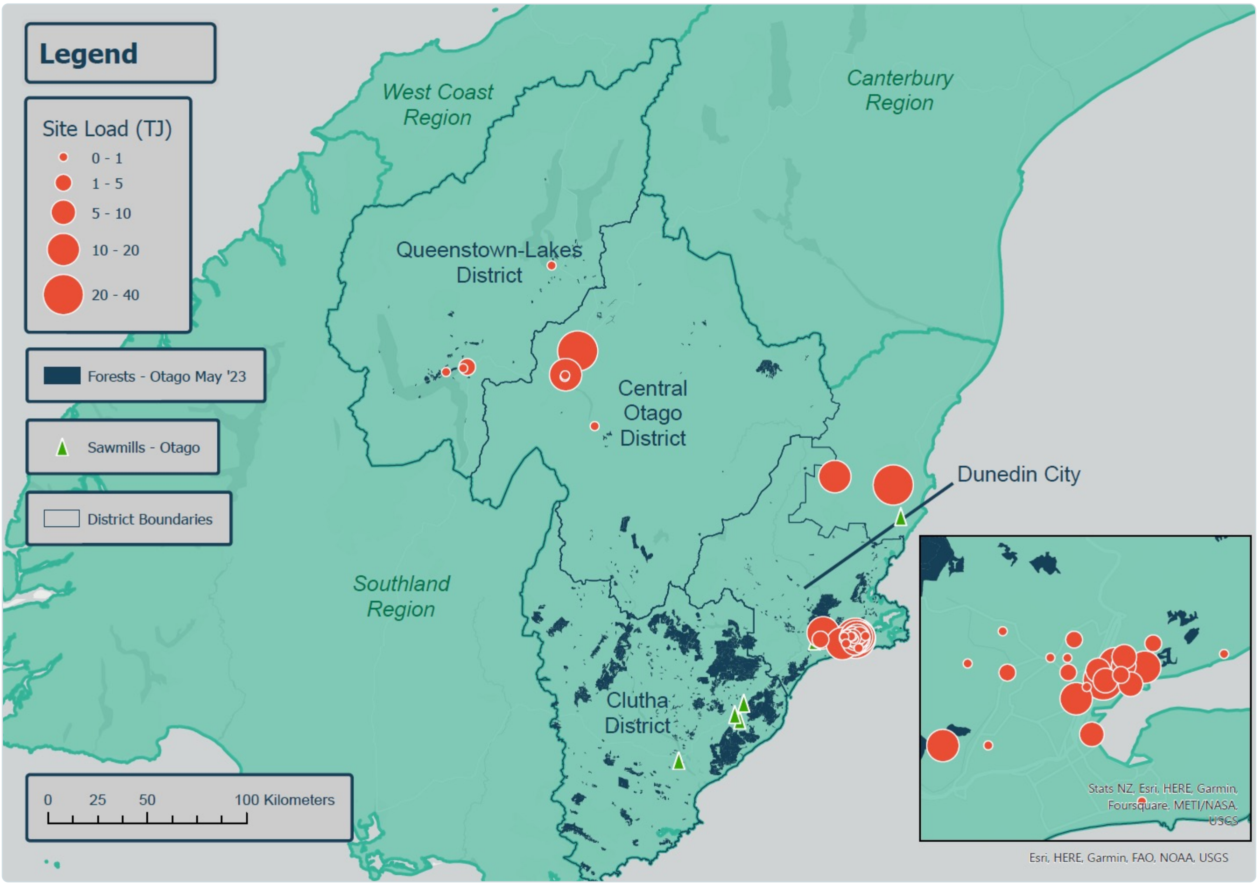
- The Roundtable for Sustainable Biomass, Biofuels, and Biomaterials (RSB), which states that no roundwood should be used for bioenergy.
- The International Sustainability and Carbon Certification scheme (ISCC), which discusses deforestation.
- The European Union Renewable Energy Directive II (RED II), which aims to limit the risk that biofuels, bioliquids and biomass fuels trigger indirect land use change.

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

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

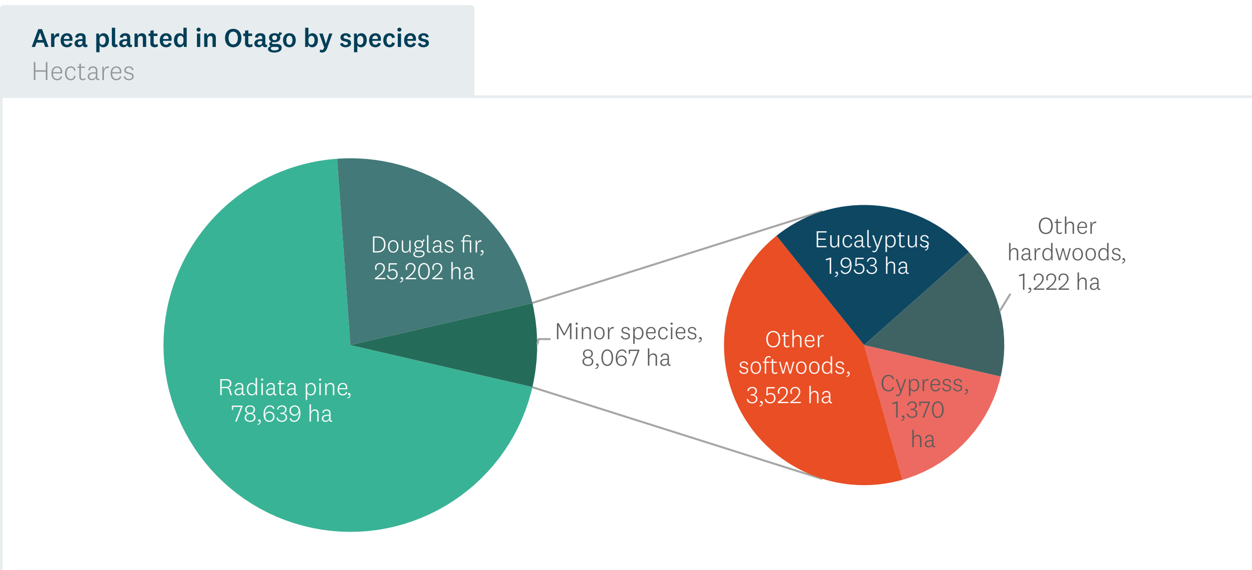
8.3 Otago regional wood industry overview

Figure 34 – Map of Otago forest resources and wood processors. Source: Ergo



The Otago region has approximately 111,000 ha of planted forests. These forests are dominated by radiata pine and Dougla fir (Figure 35). Other species include softwoods, eucalyptus and hardwood species.

Figure 35 – Area and species planted in Otago (at 1 April 2021). Source: Ahikā



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

The forestry and food processing sector have partnered with Government to develop a Forestry and Wood Processing Industry Transformation Plan[53] which is focused on increasing the total area of forestry and getting greater value from wood. This includes significantly increasing the areas of trees on farms and increased domestic processing. Additional domestic processing within New Zealand may result in greater quantities of processing residues being available as an energy fuel. Increased planting of trees on farms also contributes to environmental and community benefits so is expected to occur over the next few years.

8.3.1 Forest owners

The region has five main corporate forest owners, accounting for approximately 67% of the radiata pine and Douglas fir estates.

Table 8 – Otago Region forest estates

	Radiata pine (ha)	Douglas fir (ha)	Minor species (ha)	Total
City Forests	15,617	2,237	745	18,599
Ernslaw One	4,150	10,500	1,350	16,000
Port Blakely		1,600		1,600
Rayonier Matariki	4,720	2,560	540	7,820
Wenita Forest Products	22,270	2,020	435	24,725

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

City Forests is one of New Zealand's oldest forest companies with over 100 years of forest growing history. The company owns or manages nearly 19,000 hectares of production forest growing, mainly adiata pine, on over 24,910ha of land within an 80km radius of the city of Dunedin.

Ernslaw One has the third largest estate with their forest operations in Otago dominated by Douglas fir species.

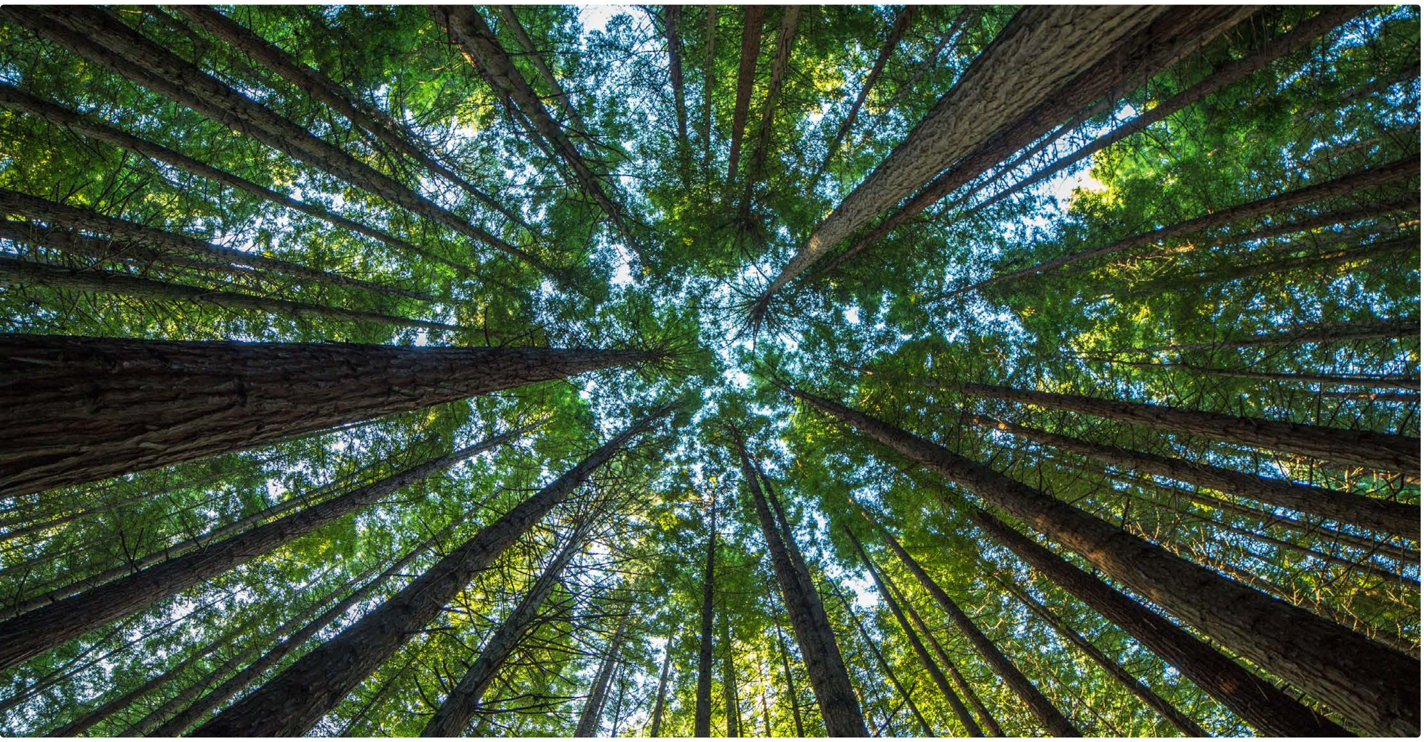
Port Blakely owns 1,600ha in the Otago region solely comprised of Douglas-fir. However, the majority of the estate is less than 23 years old, so will not be harvested for at least another 20 years.

Rayonier Matariki Forests has large estates throughout New Zealand including in Otago. The majority of their Otago estate is located within 50km from Milton. The estate is mostly comprised of radiata pine and Douglas-fir and some minor species.

Wenita Forest Products manages a forest area of 30,000ha across Otago. The three main forests, Otago-Mt Allan, Berwick and Coastal Otago, in this assessment account for nearly 25,000ha, mostly radiata pine.

8.3.2 Wood processors

There are five major processors in Otago, mostly creating products for the domestic market, using logs purchased from the forest companies. These products include building and farming products. The main residues from wood processors are sawdust, bark, woodchip, shavings and post peeling (see definitions for each type in Section 8.5.1).



Pan Pac Otago is owned by the Oji Group (Japan), and is the largest wood processor in the region. The site operates a modern sawmill, biomass boiler, continuous kiln and dry-mill year round and is ideally situated near large corporate forest estates. Pan Pac utilise a portion of their residues as boiler fuel (mostly sawdust and bark) and chip is sent to Daiken in Mataura. At this stage, Pan Pac has some very high-level plans to expand the site, but it is not in the near future. If this does eventuate, it has the potential to increase bioenergy supply for the region. All residues from Pan Pac are utilised onsite or sent to Daiken.

8.3.3 Daiken Southland

The medium density fibreboard (MDF) plant in Mataura is the single largest consumer of low-grade domestic chip logs and woodchip in Otago and Southland. Miller (2015) estimated that the plant consumes 350,000-390,000 tonnes per annum from Otago and Southland. We do not expect this volume to have changed over the last five years. The MDF plant provides a reliable and consistent source for low grade logs and many forest owners make a small margin but see this option as a cost recovery for preparing the forest for the next planting rotation.

The current gross rate of $45-$57 per tonne (including transport and operations costs) means that the maximum distance for cartage is currently Dunedin. However, interviews with forest owners indicate that this cost has started to increase due to competition for bioenergy.

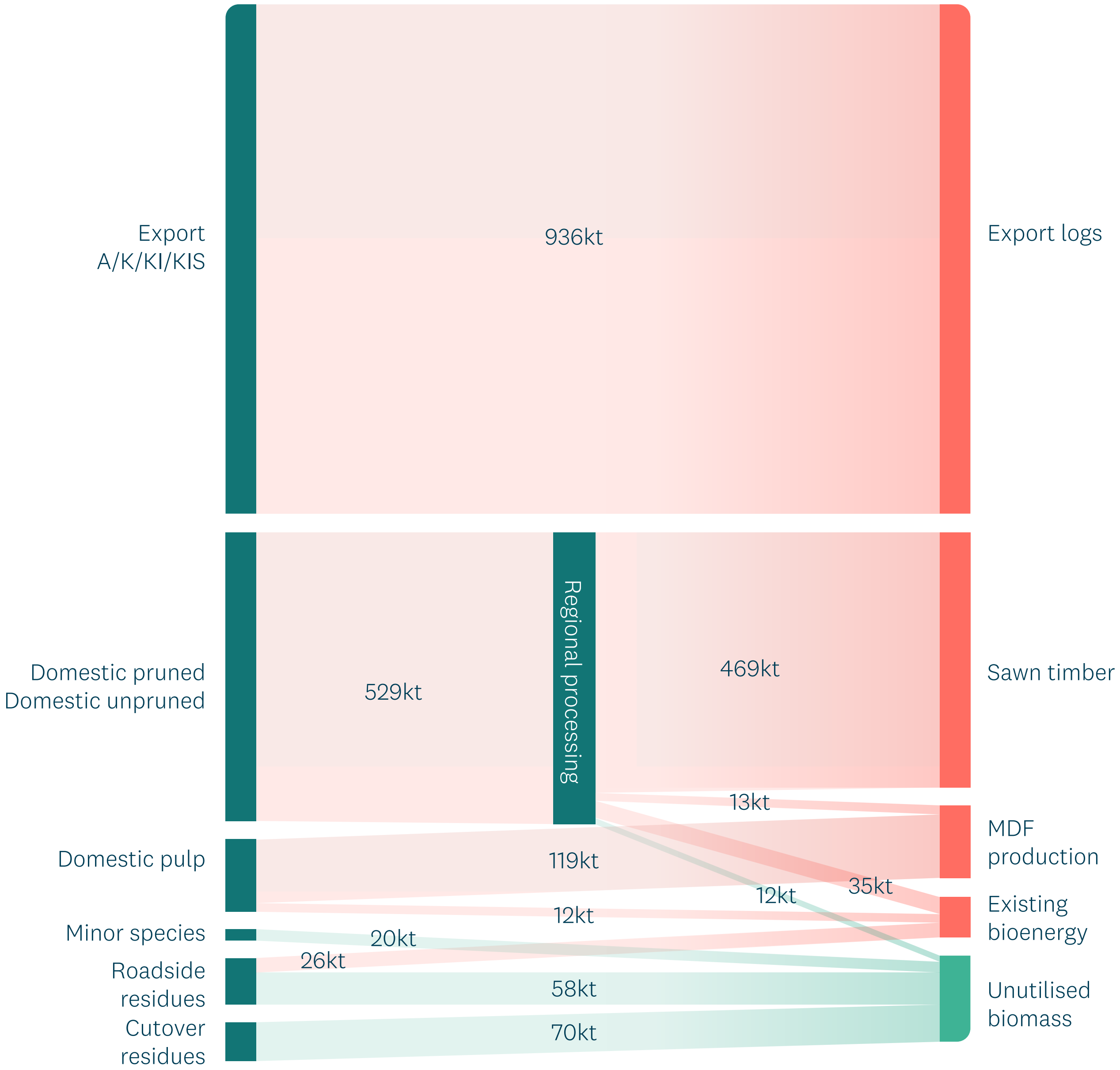
8.4 Assessment of wood availability

This section considers:

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

The outcome of this section is summarised in Figure 36. Wood flows that could be utilised for new bioenergy demand from process heat are shown in green.

Figure 36 – Wood flows in Otago. Source: Ahikā, Margules Groome



8.4.1 The Wood Availability Forecast

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

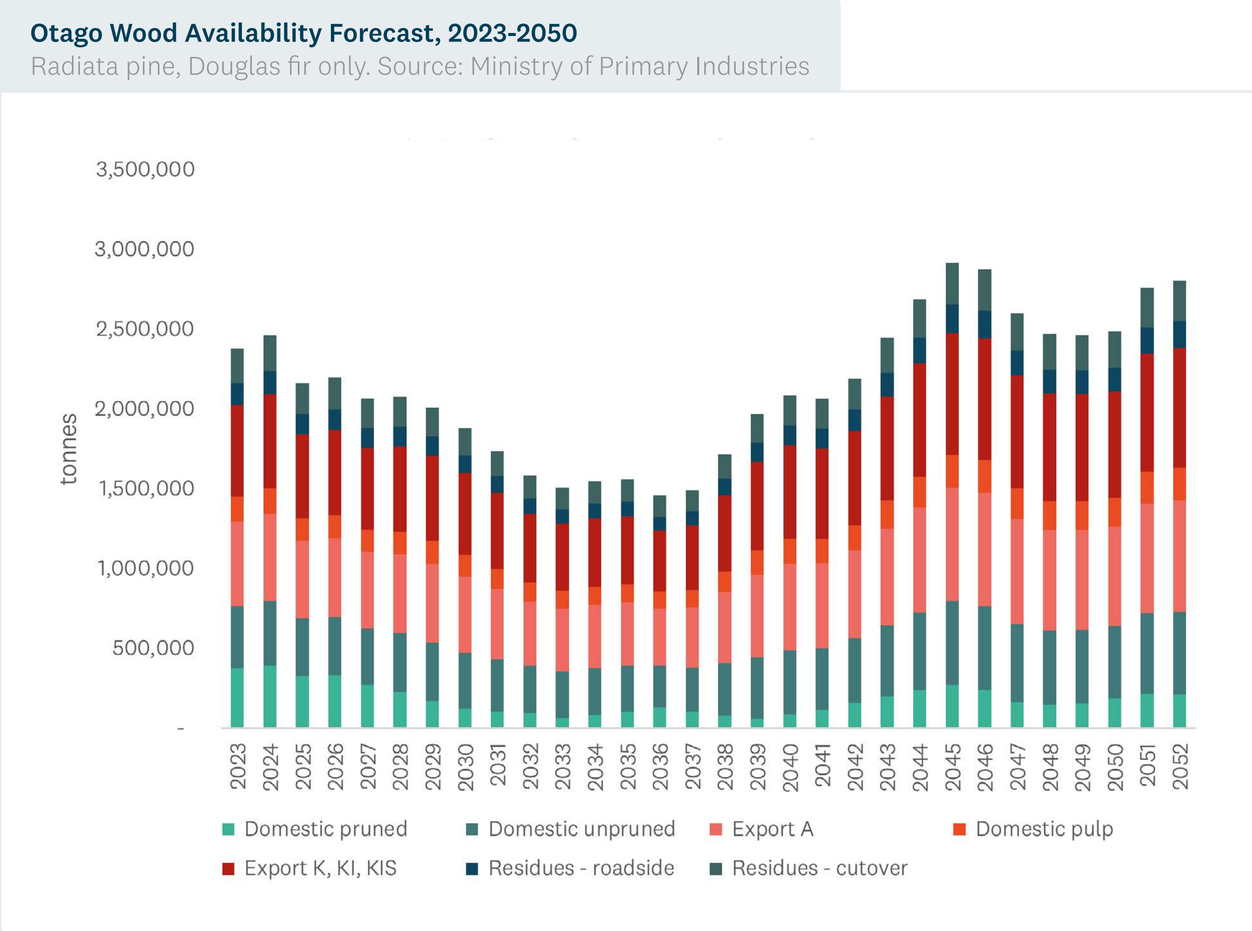
In Figure 37 total volumes are broken down into log grades using national exotic forest description (NEFD) data and the log-grade split for Otago forest owners as provided for the WAF. This has been compared with log-grade data provided by forest owners to ensure the two sources are aligned and reflect the Otago market.

Key log grades are:

- **Export grade** – This includes A, K, KI and KIS grades logs exported to Asia.
- **Domestic grade** – This includes pruned, unpruned, and pulp log grades. These grades go to domestic markets including wood processors and firewood.
- **Harvesting residues** – A by-product of harvesting and a primary source for bioenergy and firewood. It is commonly referred to as 'billet' wood; here it is split into 'roadside' (skid site, roadside and easily accessible residues) and 'cutover' (residues from stems and branches left in the forest and not as easy to access). Residue volumes are determined as a portion of total recoverable volume based on the average of estimates from harvesting studies by Hall (1994), Robertson and Manley (2006) and Visser (2010). The costs of recovering residues are discussed further below.

Export grade volumes are sent to Port Otago. Domestic grades are utilised in Otago by local processors and Daiken Southland.

Figure 37 – Wood resource availability in Otago region, 2023-2050. Source: Ministry of Primary Industries.



As can be seen from Figure 37, the total available wood resource falls over the period 2026-2036 and increases shortly after the end of the RETA study period (2037). This occurs due to the age distribution of the existing forests (around half of radiata pine is more than 15 years old), combined with the assumptions in the WAF model regarding when forests are harvested.

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

The large-scale owners hold 65% of the modelled resource, and small-scale owners hold the remainder. A key issue is the timing of harvesting by small-scale forest owners. The harvest age can vary markedly even between neighbouring properties. The volumes forecasted by larger forest owners are subject to alteration because of changes in harvesting intentions or changes in the resource description (for example, areas and yields). But a higher level of confidence can generally be assumed for these owners than for small-scale owners, whose harvest intentions are less clear due to being more reactive, and with less accurate resource descriptions.

8.4.2 Minor species

In Otago, minor species account for 7,200 hectares in the NEFD, and the large estate owners account for 43% of the minor species that include softwoods, cypress, eucalyptus and other hardwoods. It is assumed that the minor species are recovered at a rate of 370 tonnes per ha, and that 60% of this could be used for bioenergy. Averaged over 2023-2037, and accounting for the age class distribution, minor species could thus contribute 20,100 tonnes per annum as bioenergy.

8.5 Insights from interviews with forest owners and processors

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

8.5.1 Processing residues

Five processors in the region were interviewed to better understand both the potential residues from processing, as well as the current demand for these residues for bioenergy.

The main residues from wood processors are:

- **Sawdust** is the residues from sawing logs and is one of the more difficult products to sell. It can be mixed with other residues and sold as animal bedding. It could also be made into wood pellets but needs to be dried beforehand.
- **Bark** is mostly created at the port when handling, storing and loading logs but small volumes are also available from processors.
- **Woodchip** is created onsite from all viable offcuts and is sold for landscaping, animal bedding or to MDF.
- **Shavings** are created when dressing the timber which creates a finished product smooth and clean. Shavings are usually created after the timber has been dried so it is light and dry and is good boiler fuel.
- **Post peelings** are the residues created from making round posts (fencing, poles, lamppost) and are thin and long in shape making them difficult to handle. Additional processing may be necessary to create a more uniform product for bioenergy.
- **Slabwood** is produced from the offcuts of milling and is sold as firewood.

Table 9 shows the types of processing residues readily available from Otago processors.

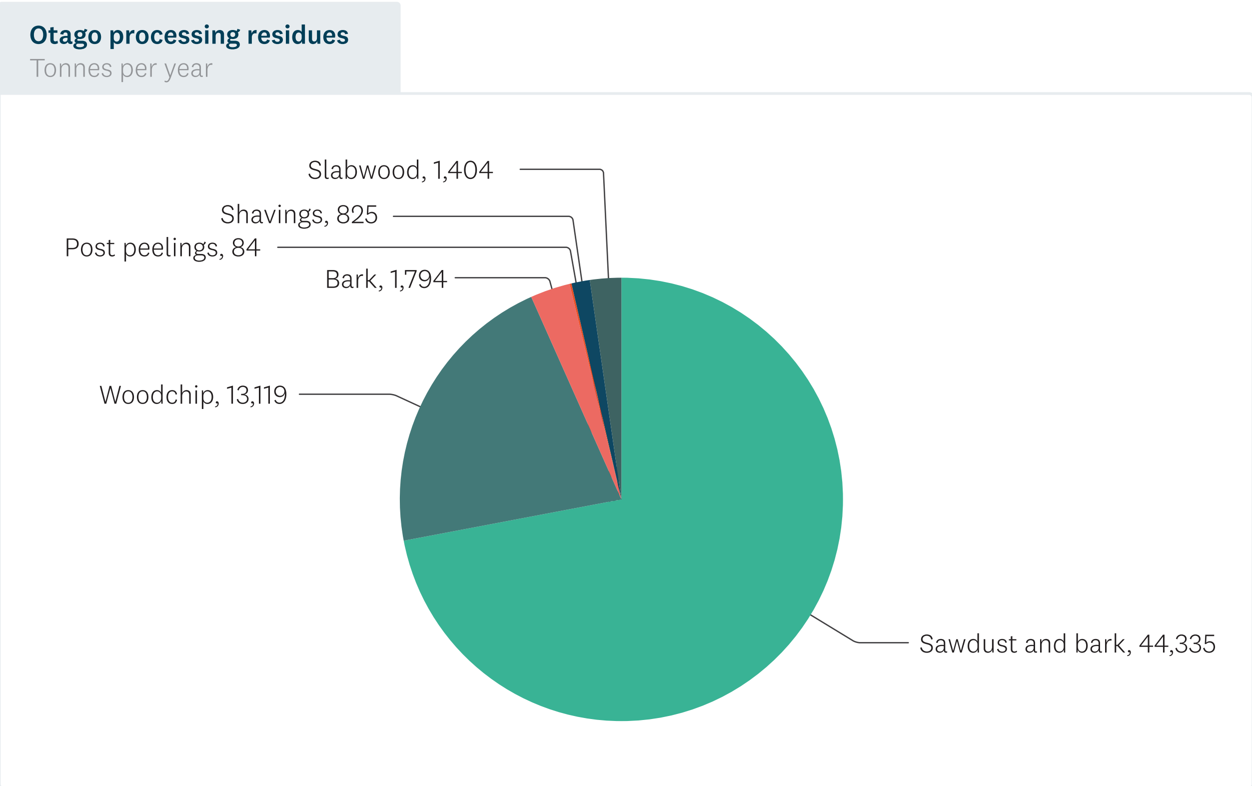
Table 9 – Products readily available for bioenergy from processors in Otago. Source: Ahikā

	Sawdust	Woodchip	Shavings	Post peelings	Bark	Slabwood
Gorton Timber	x	x				
Hewvan Enterprises	x	x	x		x	
Hollows Timber	x		x	x		
Timpack Ltd			x			x
Otago Lumber	x	x	x	x		

The interviews conducted suggest that there are, on average, 59,767t per year of processing residues created in Otago, the majority of which is sawdust and bark (Figure 38). 35,283t per year of these residues are already being utilised for bioenergy in the form of sawdust, bark and shavings. Another 13,119t per year is sent to the Daiken MDF plant. The remainder (11,365t) is used as boiler fuel.

Pan Pac is the largest wood processor in Otago but did not provide information for this assessment. Ahikā estimated their residue supply, of sawdust and bark, at 35,000 tonnes per year. This is all utilised internally as boiler fuel. For completeness, we include these volumes on both the supply side and demand side of this analysis.

Figure 38 – Otago processing residues, tonnes per year (15-year average). Source: Ahikā Interviews



8.5.2 In-forest recovery of biomass

In forest residue volumes were estimated by Margules Groome as part of the WAF[54]. In-forest volumes have been split into two categories:

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

Based on interviews with forest owners, only 25% of roadside residues are being recovered, and are being used for bioenergy. No cutover residues are currently being recovered. The issues faced with in-forest residue recovery include:

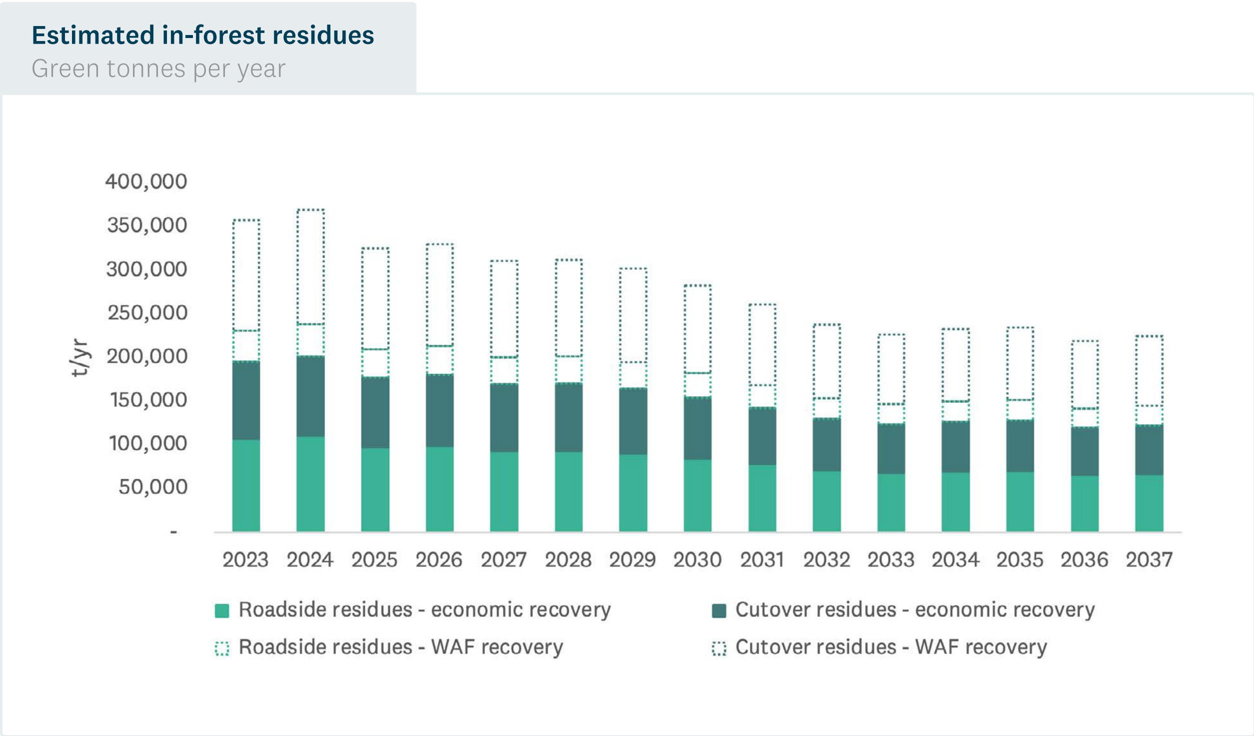
- A significant proportion of the terrain in Otago is steep; commensurately, there is a relatively low percentage of hauler-based terrain in Otago. Hauler-based terrain occurs on reasonably accessible land, hence a lot of processing occurs at the skid site. With the low percentage of accessible land, more residues are being left in the cutover, and therefore are less accessible.
- Commentary from foresters suggests that some of the roadside volumes gets left behind because the market price would not exceed the cost of collection and distribution.

A more definitive estimate of cutover recovery resources and cost requires an assessment of the underlying terrain, as recovery on steep hauler country is likely to be substantially lower than on ground-based country. This information was not available for the Otago RETA. We have scaled back assumed recovery of harvesting residues from the theoretical potential in the WAF (shown in Figure 37), using expert opinion.[55] This applied more pragmatic recovery factors for different volumes, based on assumed methods of recovery (ground-based and hauler-based), and resulted in a reduction of WAF roadside and cutover volumes by 25% and 59% respectively. Realistic harvesting residue estimates average 127,865t per year, albeit with higher volumes initially and lower volumes later on (see Figure 39).

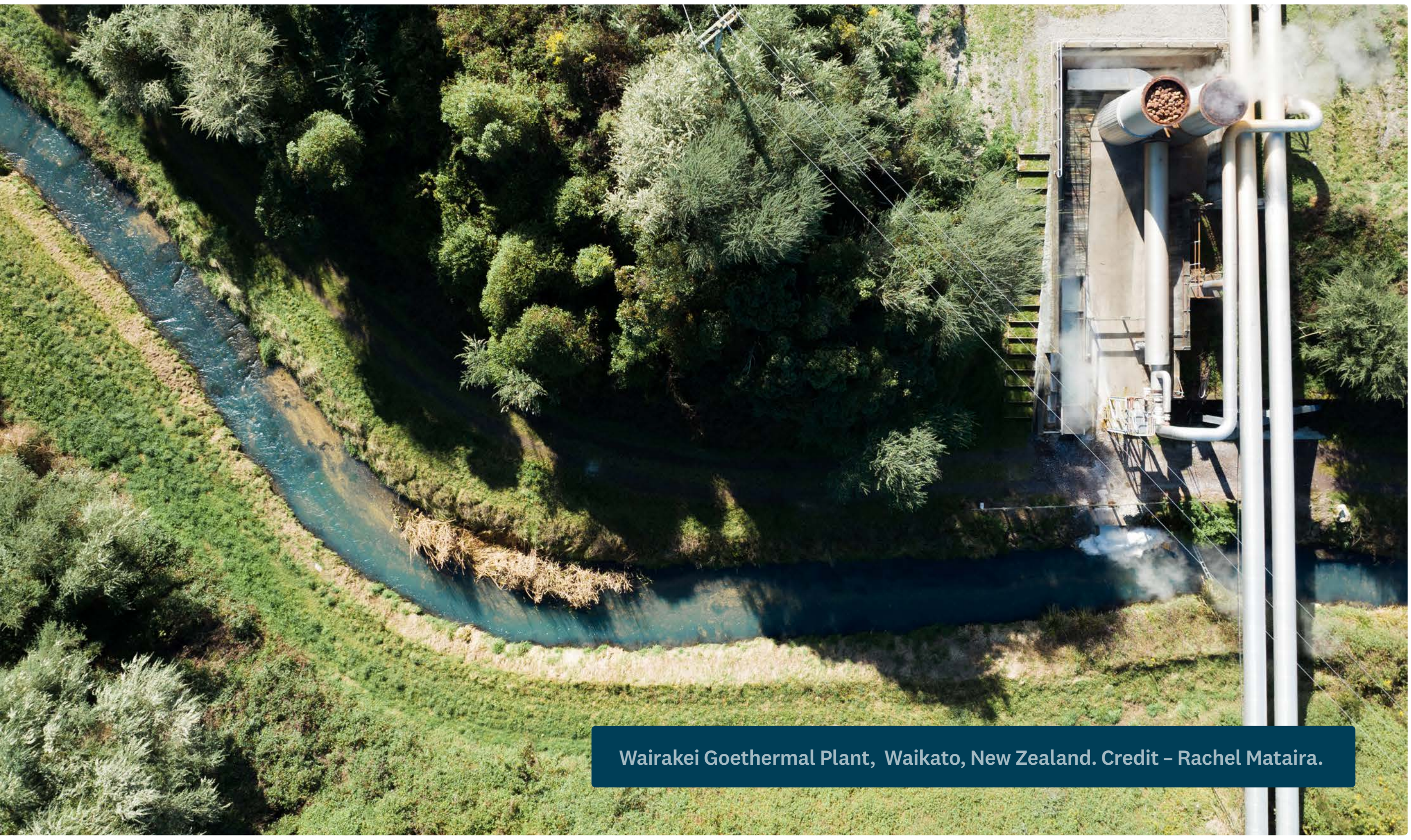
[54] As noted above, this estimate was based on the research of Hall (1994), Robertson and Manley (2006) and Visser (2010, 2018).

[55] Margules Groome, 2023.

Figure 39 – Estimated in-forest residues, WAF vs expert judgement. Source: Ahikā, Margules Groome



The final assessment only uses the pragmatic estimate of recovery volumes.



Wairakei Goethermal Plant, Waikato, New Zealand. Credit – Rachel Mataira.

8.5.3 Existing bioenergy demand

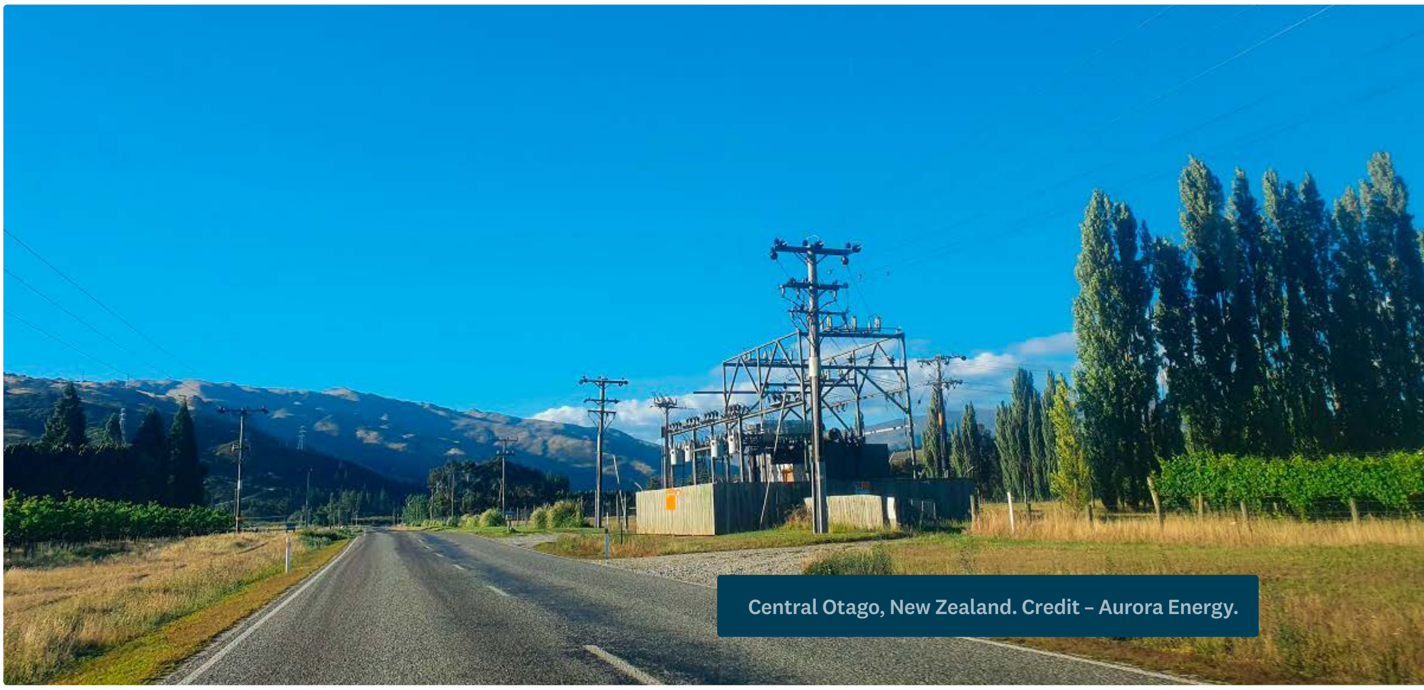
The interviews highlighted where some of the sources of potential biomass are already being used for bioenergy:

- A large proportion of processing residues (sawdust and bark) are being used internally by wood processors as boiler fuel.
- Some roadside residues are being collected and used for bioenergy.
- Some domestic pulp is being sold as firewood.

These volumes are summarised in Table 10. In the analysis below, we assume that these bioenergy demands continue into the foreseeable future.

Table 10 – Bioenergy sources already utilised (average 2023-2037)

	Bioenergy already utilised (t/yr)
Wood processor residues	35,283
In-forest residues – roadside	25,850
In-forest residues – cutover	0
Pulp (firewood)	11,834
Total	**72,967**



Central Otago, New Zealand. Credit – Aurora Energy.

8.6 Summary of availability and existing bioenergy demand

Figure 40 below shows our overall assessment of the forest (and forestry by-product) resources in Otago.

Figure 40 – Wood resource availability in the Otago Region. Source: Ahikā, Margules Groomeand additional EECA analysis

Otago woody biomass that could be used for bioenergy

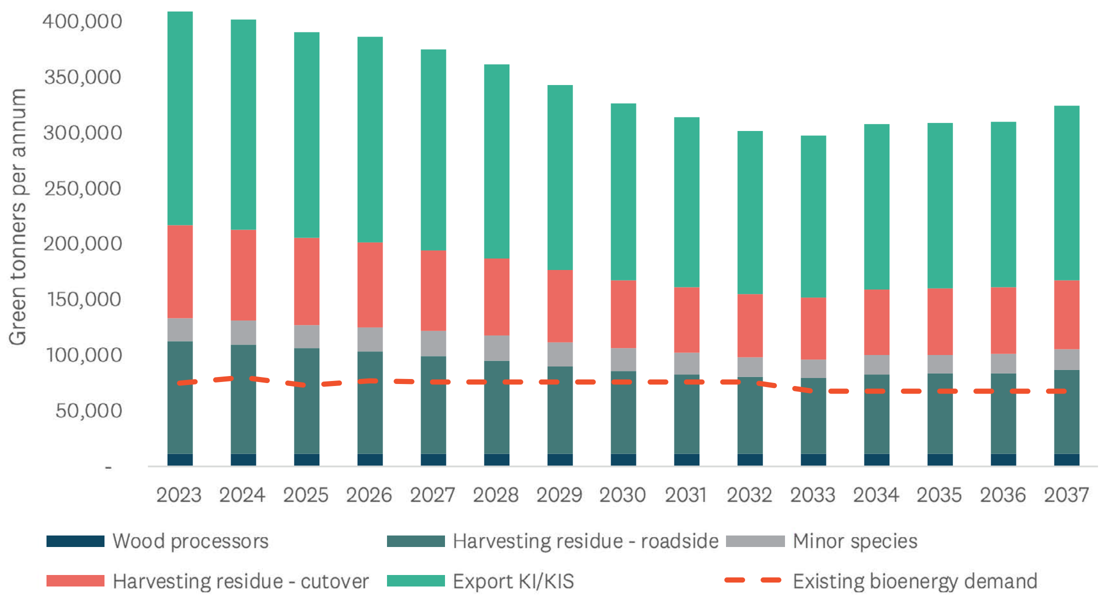


Figure 40 shows there is significant scope to increase the use of bioenergy from the relatively low level today (~73,000t, or 524TJ). We note that domestic pulp (for firewood or MDF production) is excluded from the availability assessment on the basis that the potential consumption of woody biomass for bioenergy should not disrupt domestic markets for timber. Export A-grade and K-grade timber are also excluded due to cost (see below).

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

8.7 Cost assessment of bioenergy

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

8.7.1 Cost components

Margules Groome developed a calculator to estimate delivered bioenergy prices for the various products identified in this assessment. A key cost component is the cost of transporting the material from source to a hypothetical processing location, which for the Otago Region has been assumed to be Milton. Depending on the source, prices have been determined as follows:

- **Wood processing residues** – The price for the wood processing residues is the sum of the cost of the material at the processing mill plus the cost of transporting it to the hub. It is assumed that the material is already in a form that could be consumed for energy production, hence only storage, handling and hub margin costs are added.
- **In-forest roadside and cutover volume** – A forest owner's costs (collection, loading, transport from forest to biomass hub) are added to the biomass hub costs of chipping, storage, and handling. This methodology is also used to calculate the bioenergy cost for material sourced from the harvesting of minor species (see discussion below).
- **Diverted export volume** – All the export volume from Otago is assumed to be transported to Port Otago at present. The difference between the transport cost to Port Otago and to the biomass hub is subtracted from the at-wharf gate export price. The biomass hub costs of chipping, storage and handling the biomass is then added to the price.

8.7.1.1 Costs associated with harvesting residue recovery

The cost of recovering harvesting residues are the most challenging to estimate. 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. Notwithstanding this, we understand the three broad types of models are:

1. **Full cost model** – In this model, the harvesting contractor gets fully paid (from bioenergy revenues) for the volumes recovered from the forest. This is the highest cost approach, but should result in a high level of residue recovery.
2. **Reduced cost model (or 'integrated' model)** – The harvesting contractor is paid a reduced harvesting rate for residues to encourage better overall recovery, by efficiently integrating the recovery of all wood from the forest. Normally the reduced residue harvesting cost is around half the normal harvesting cost. This will be a lower cost approach than the full cost model, but should achieve similar levels of volume recovery due to the efficiencies from integration.

3. **Recovery model** – A separate operation is commissioned once the harvesting crew has left the site. This model assumes that the residues do not incur an additional harvesting cost over and above what was paid for the domestic and export grade timber (as the residues are assumed to be left at skid sites by the main harvesting contractor). Whilst this is the lowest cost model, recovery volumes will likely be limited due to the separate operation not having access to the same equipment, methods and ground coverage used by harvesting contractors.

A more mature residue market would help bring more transparency both to the value of residues, and the 'true' cost of residue recovery. EECA believes that the development of an 'energy grade' (E-grade) for harvesting, such as that described by Margules Groome, would significantly hasten the development of our understanding of the costs of collection, and thus the development of bioenergy markets. As outlined by Margules Groome, the concept of E-grade[56] is simple; to develop a 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.

Margules Groome believe that this would lead to the following benefits:

- Reduce the number of cuts and handling required by processor heads in the field and on the skid. Delimbing would be minimised in the field, and only on larger diameter sections of the log on the skid.
- Reduce the required landing size and associated engineering costs due to the reduced number of sorts, and reduced piling of residue and offcuts, and the space needed for such material.
- Reduce environmental risks due to smaller landings and less 'birdnesting' of forest waste.
- Provide the opportunity to derive value from sapstained fibre such as from trees that are wind thrown on exposed edges created from road lining.
- More competitive harvesting rates.
- Higher quality of fibre due to less soils and other contaminants.
- Less handling of material at the processing plant / chipper.

EECA agrees that 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.

8.7.1.2 Estimated costs of bioenergy

Table 11 and Figure 41 show these costs in terms of mass and (in $/t biomass) and energy equivalent ($/GJ). This requires an assumption about the moisture content of the underlying fuel. We use calorific value associated with a moisture content of 55%. In reality, the moisture content will vary between the different sources listed in Table 11; this will need more detailed consideration by process heat users contemplating conversion to biomass.

[56] Margules Groome refer to this as a 'E-grade *log*', however EECA recommends referring to it simply as E-grade as the definition should be broad enough to include biomass that may not necessarily be logs.

Table 11 – Sources and costs of biomass resources in the Otago region, average value 2023-2037. Source: Margules Groome (2023)

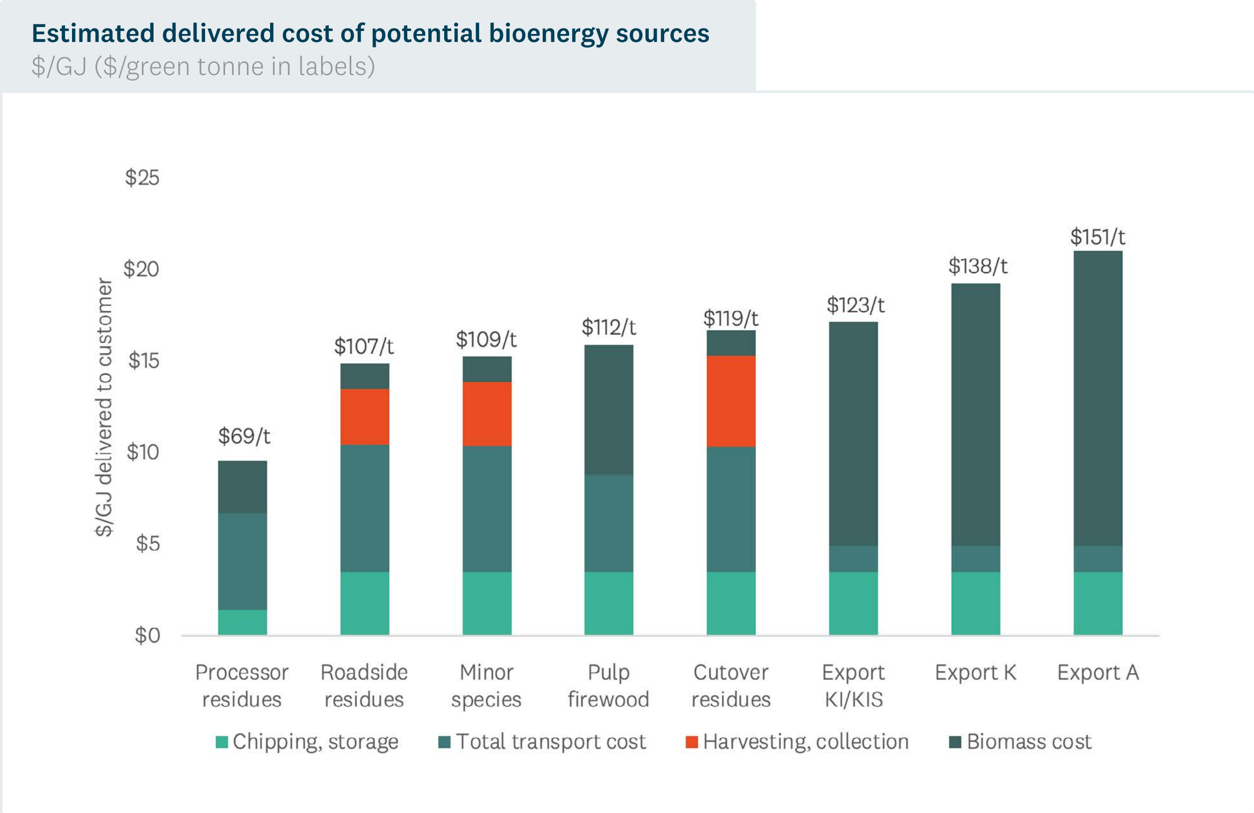
Bioenergy source	Cost of biomass source ($/t)	Harvesting and collection ($/t)	Chipping and storage ($/t)	Transport to process heat user ($/t)[57]	Total cost delivered to user's site ($/t)	Total cost delivered to user's site ($/GJ)[58]
Processor residues	$20.60	$0	$10	$38	**$68.60**	**$9.50**
Roadside residues	$10	$21.77	$25	$49.80	**$106.60**	**$14.80**
Minor species	$10	$24.94	$25	$49.50	**$109.40**	**$15.20**
Cutover residues	$10	$35.56	$25	$49	**$119.60**	**$16.70**
Export grade KI and KIS logs	$87.90	[included]	$25	$10.20	**$123.10**	**$17.10**
Export grade K logs	$103.10	[included]	$25	$10.20	**$138.30**	**$19.30**
Export grade A logs	$115.90	[included]	$25	$10.20	**$151**	**$21**
Pruned sawlogs	$164.30	[included]	$25	$10.20	**$199.40**	**$27.80**

The figures in the far-right column of Table 11 include the cost of both primary transport from the forest to a hub that is assumed to be at Milton, as well as 'secondary' transport from the Milton hub to the process heat user. For secondary transport, we have assumed $18/t ($2.50/GJ) over a distance of 60km from the hub. This is consistent with previous RETA reports, and fairly represents the cost of transport between Milton and Dunedin, where many of the RETA sites are. However a number of sites are over 100km – and up to 210km (Queenstown) – from Milton. This would result in significantly higher transport costs if the biomass was purchased from the Milton hub. It is not clear whether this would occur in reality, as these RETA sites may be able to secure a biomass source closer than Milton. Our sensitivity analysis considers the impact of higher transport costs for the potential biomass customers that are further than 60km from the Milton hub (see Section 7.4).

[57] Note also that for volumes diverted from export, a reduction in transport costs is warranted, as these are currently transported from the Otago to Lyttleton for export, and this component is saved if they are used locally.

[58] Conversion in energy equivalent assumes a net calorific value of 7.184 MJ/kg (55% moisture content), and 1m3 = 1,000kg. We also note that this is a price of energy as delivered to the gate and is therefore not directly comparable to an electricity price, due to the relatively lower biomass boiler efficiency compared to an electrode boiler (or a high temperature heatpump, where applicable). We expand on this comparison in Section 8.

Figure 41 – Estimated delivered cost of potential bioenergy sources, average value 2023-2037. Source: Margules Groome (2023)



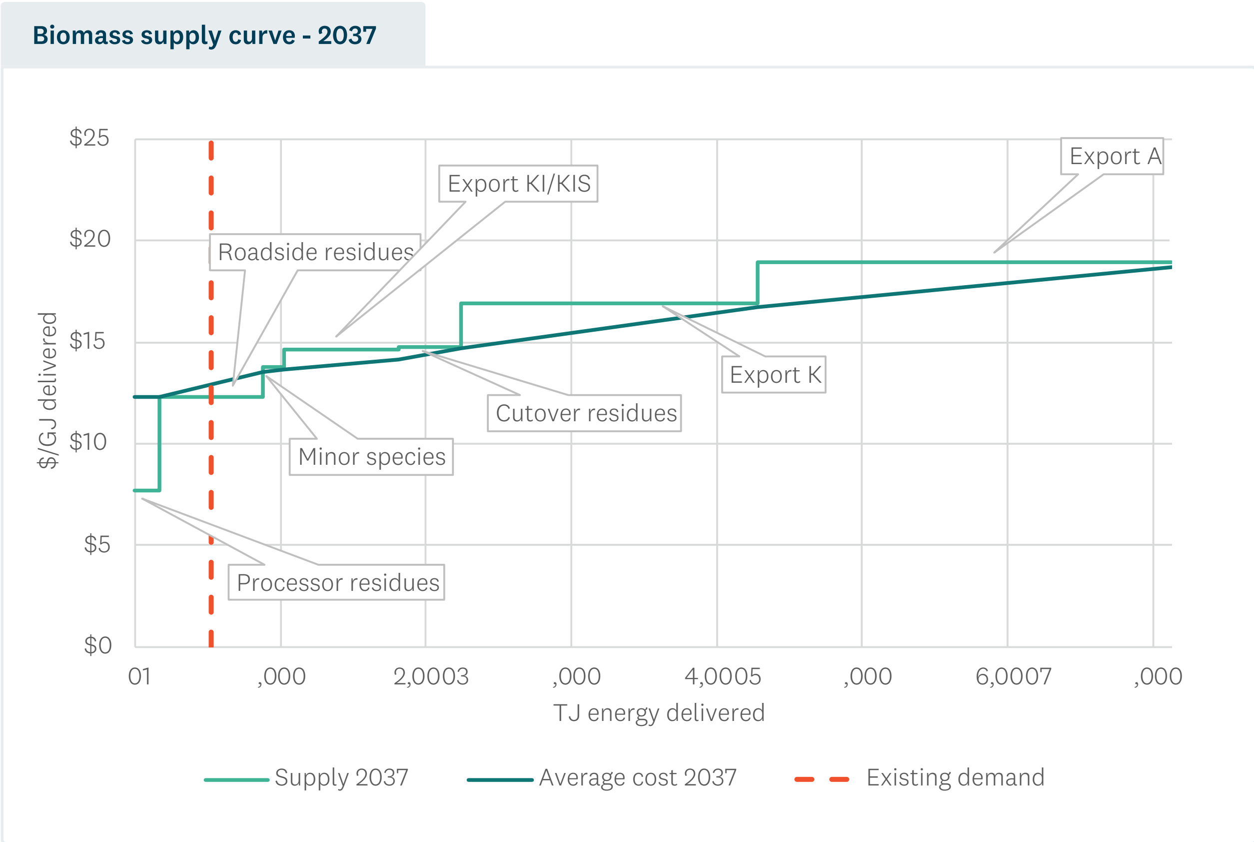
We reinforce that we retain export grade A logs in the analysis not because we believe these are sustainable or practical sources of bioenergy. Rather we use them in the supply curve to represent 'scarcity values' if our scenario analysis below should indicate that other more plausible and sustainable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

8.7.2 Supply curves

To convert these costs into an indicative market supply curve, we use the corresponding volumes for each category of resource from the analysis in Section 8.6 above. Since the supply of near-term bioenergy resource availability varies through time, we produce three supply curves (in addition to current), one for each of the five year periods in the next 15 years. This is shown in Figure 42.

Note that the costs shown here do not include secondary transport costs from the processing hub to the final user, the only include transport costs from the forest to the Milton hub.

Figure 42 – Biomass supply curves in 2037. Source: Margules Groome, Ahikā



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

- If early biomass customers secure long-term contracts for lower cost processor residues or in-forest residues (indicated by the dashed lines), they will still have access to those resources, at the agreed price, for the duration of those contracts. This is regardless of what is happening in the rest of the market. As each subsequent process heat user switches fuels, they will contract for the lowest cost resource that has not already been secured by an earlier adopter. Hence the supply curves in Figure 42 indicate the price faced by the next increment of demand, assuming that all cheaper biomass resources have been fully contracted, at least for the remaining period of the chart.
- Alternatively, the biomass market may operate on a 'spot' basis, without any long-term contracting. Every year, aggregators of bioenergy resources suitable for process heat will secure the supply, and all users will pay a price approximating the average cost across all the resources.

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

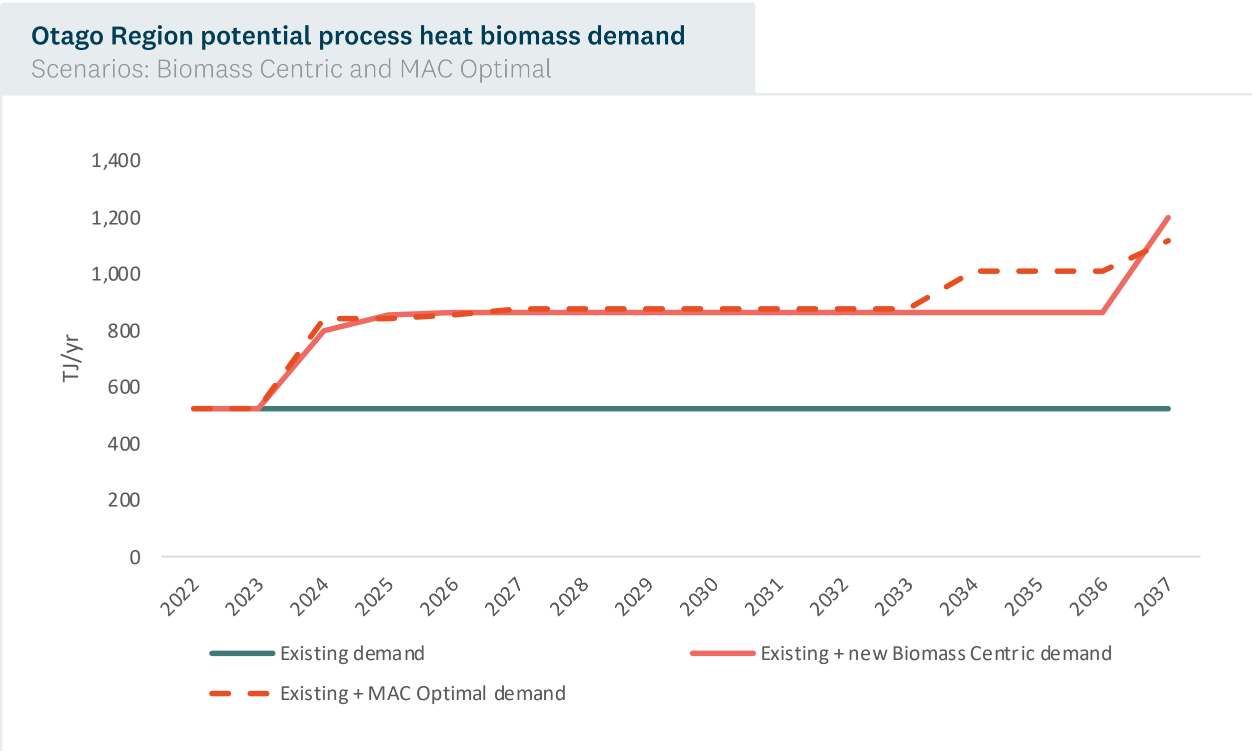
8.7.3 Scenarios of biomass costs to process heat users

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

These demand scenarios include the present consumption of bioenergy (~73,000t per annum), and assumes this continues throughout the 2023-2037 period.

Our demand curves through time (Figure 43) illustrate a scenario where biomass is selected as the fuel for every boiler conversion in the RETA study[59], i.e. it is a conservative forecast of biomass demand. The timing of each conversion (and hence when each increment will arise) is set by the dates in each organisation's ETA pathway, or, in the case where no date is set, 2036.

Figure 43 – Pathways of Otago Region bioenergy demand for process heat. Source: EECA



[59] Note committed switches to electricity are excluded.

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

Figure 44 – Biomass supply and demand in 2027. Source: Margules Groome, EECA

Biomass supply and demand 2027

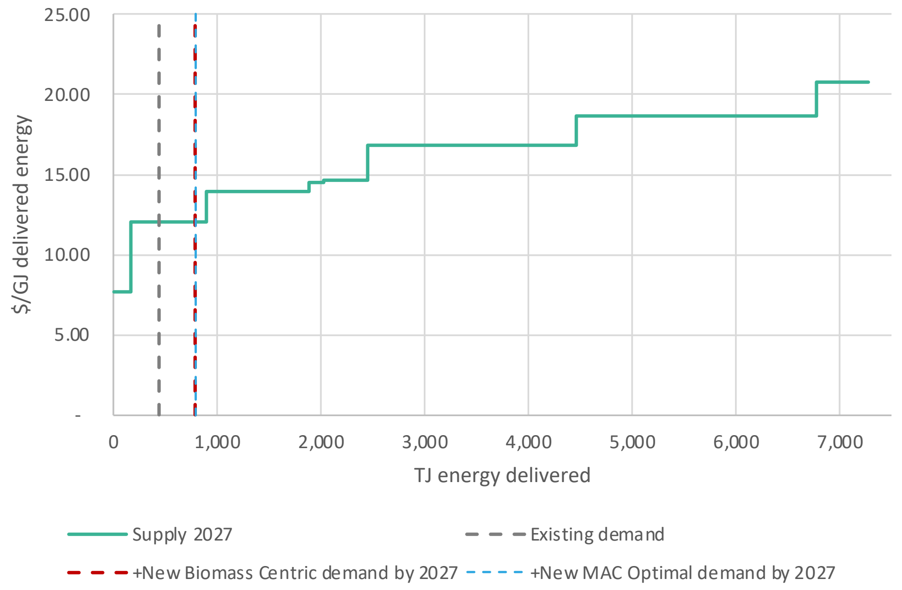
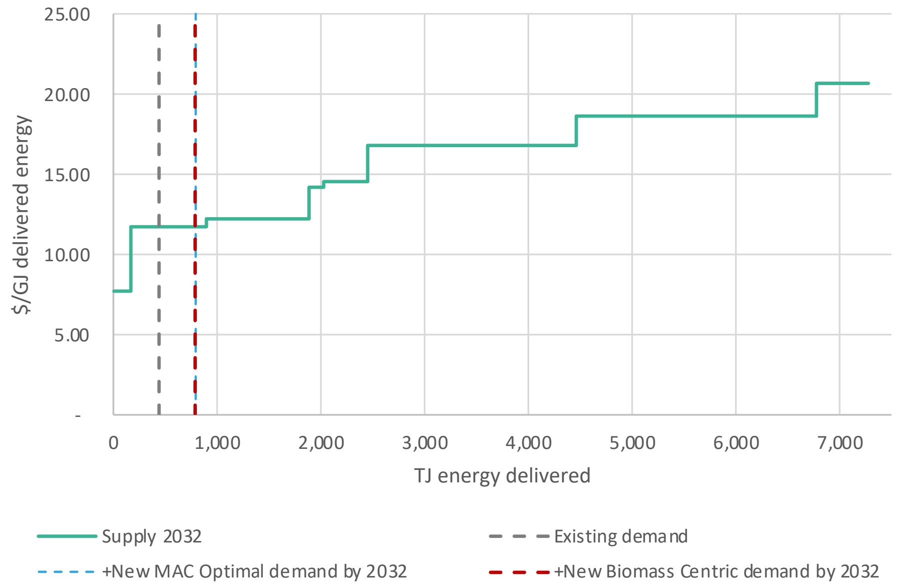


Figure 44 illustrates that the MAC Optimal pathway sees a doubling in the use of biomass compared to today.[60] By the end of 2027, the MAC Optimal pathway consumes all processing residues and the vast majority of roadside residues.

Figure 45 – Biomass supply and demand in 2032. Source: Margules Groome, EECA

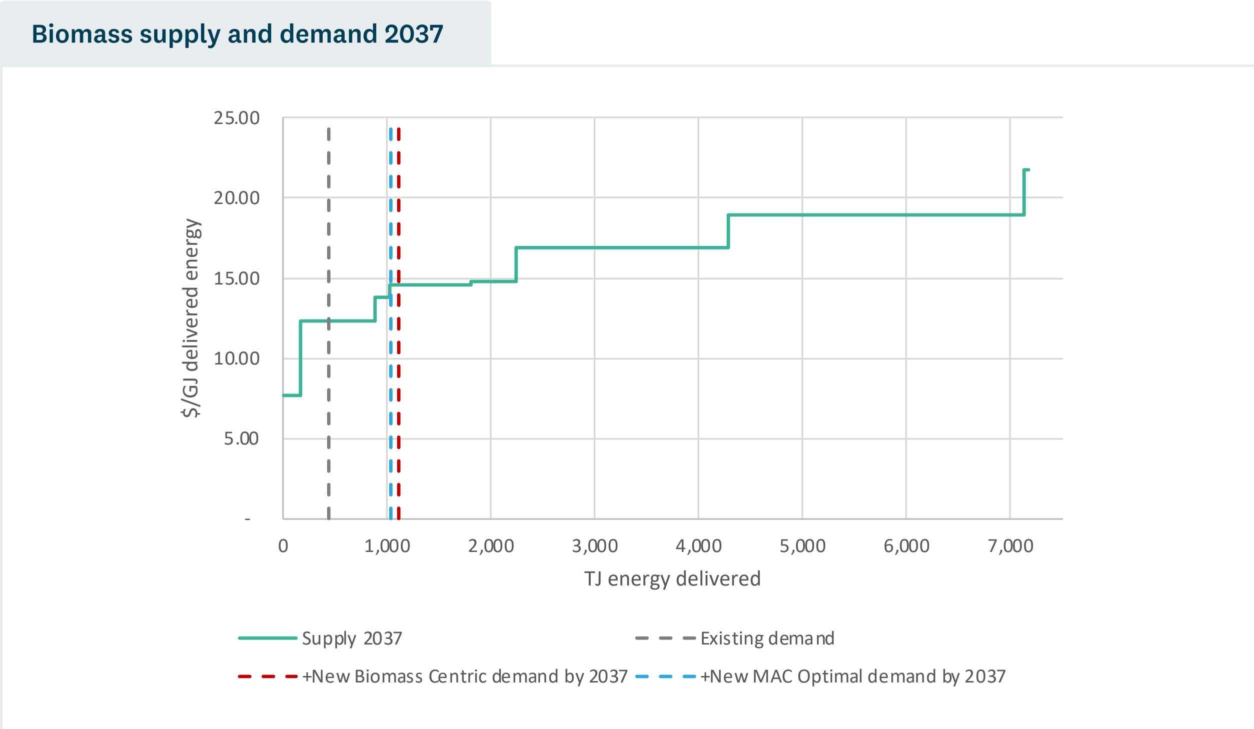
Biomass supply and demand 2032



[60] In the chart, the Biomass Centric pathway overlaps with current demand.

Figure 45 shows that no significant change in demand occurs between 2028 and 2032.

Figure 46 – Biomass supply and demand in 2037. Source: Margules Groome, EECA



In 2037, the +MAC Optimal pathway (1,032 TJ per year, including existing demand) is 135% higher than the existing demand, is using all processor residues, all minor species. Demand from the + Biomass Centric (1,114 TJ per year, including existing demand) is 154% higher than existing demand and can all be met by processor residues, in-forest roadside residues, minor species and some export KI/KIS.

McCain Factory, Canterbury, New Zealand. Credit – Chris Stanley.

9 Otago electricity supply and infrastructure

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

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

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

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

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

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

Hence the primary questions for a process heat user considering electrification are:

- What is the price of electricity likely to be, including the costs of wholesale generation, electrical losses, transmission and distribution?[61]
- Is the existing capacity in Transpower and the EDBs' networks[62] sufficient to transport electricity to their electricity-based process heat location at all points in time?
- If the networks do not have sufficient spare capacity, what is the cost, and ability of network companies, to deliver any upgrades required to accommodate the peak electricity demand of process heat users (as well as any other consumers looking to increase electricity demand in that part of the network)?
- To what extent can a process heat user use any inherent flexibility in their consumption to reduce the cost of upgrades or electricity?

This section covers these four topics.

Arrowtown, Otago, New Zealand. Credit – Aurora Energy.

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

[62] The site's spare capacity also has to be considered, of course.

9.1 Overview of the Otago electricity network

Figure 47 below shows the region's high-voltage grid (owned by Transpower), including the six GXPs where local EDBs – Aurora and OtagoNet[63] – take supply from the national grid. The 26 RETA sites considering electrification of process heat (see Table 5), plus one electric vehicle charging station in Cromwell, are also displayed. Each connect to one of these EDB networks.

Figure 47 – Map of the Otago transmission grid, location and peak demand of RETA sites

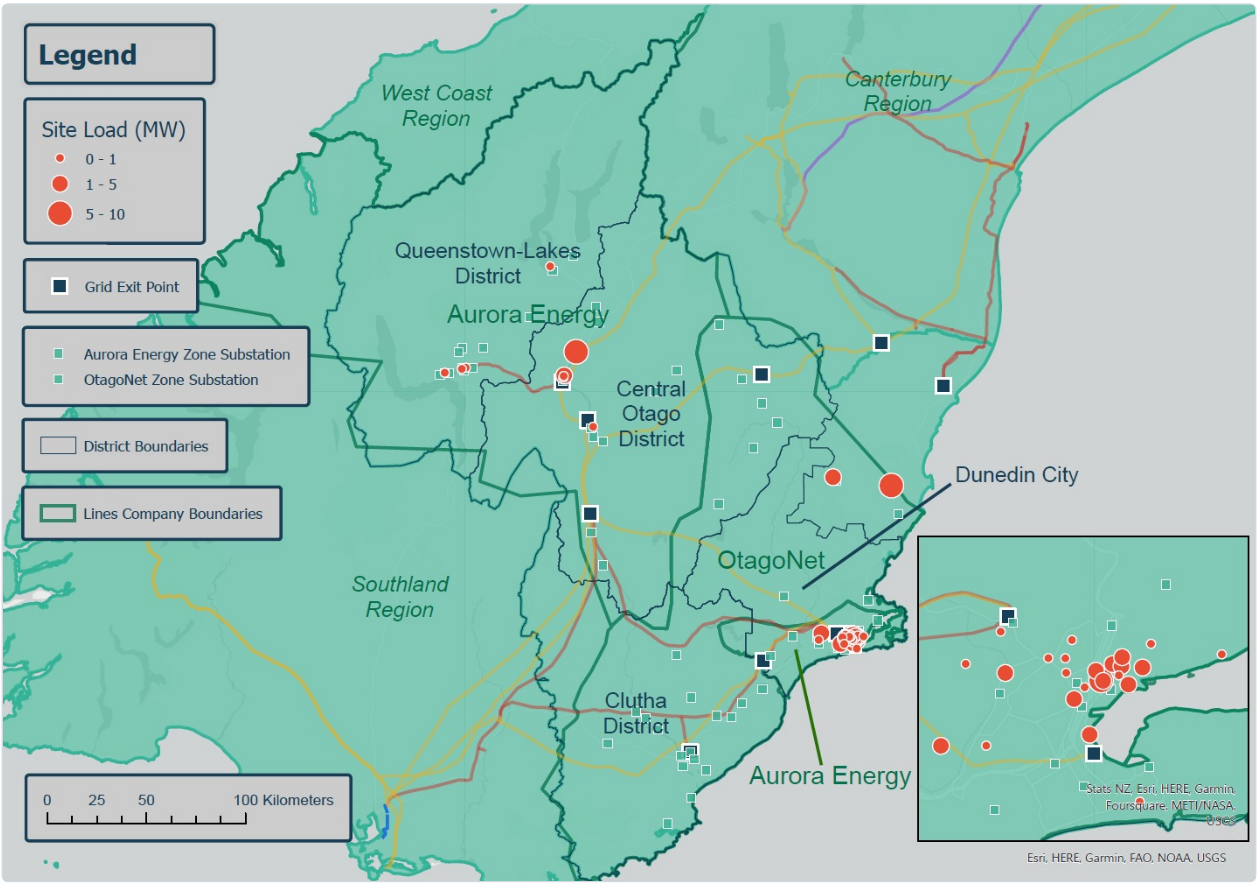


Figure 47 shows how geographically diverse Aurora's network is, spanning coastal, Central Otago and Queenstown Lakes. At a distribution level[64], each of these networks are electrically distinct. As outlined further below, this leads to some differences between the network charges in each of the three sub-networks, reflecting the characteristics of the assets and the consumers.

[63] OtagoNet is a joint venture (JV) between Electricity Invercargill Ltd and The Power Company Ltd. Electricity Invercargill and The Power Company are also shareholders of PowerNet, and it is PowerNet that manages the assets of the OtagoNet JV.

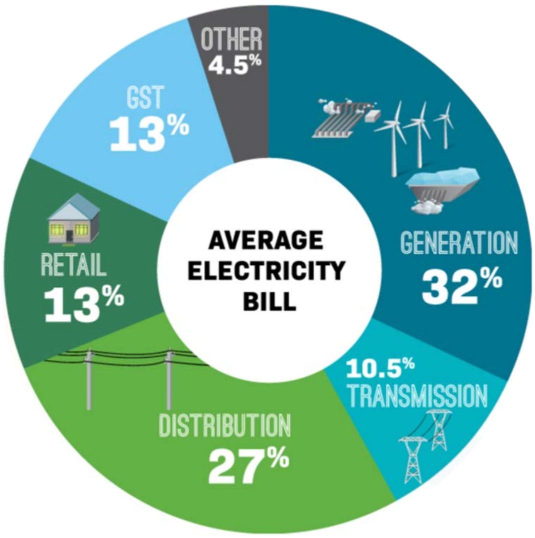
[64] Ultimately, each of the three sub-networks are connected via the national grid.

Another notable aspect of the Otago region is the degree of local embedded[65] generation (wind and hydro), in addition to the significant grid-connected Clutha scheme. The currently operating embedded schemes produce, on average, 114GWh per year – around 6% of total Otago electricity demand (~1,700GWh in 2022). Together with the ~3,500GWh annual production[66] from Contact Energy's Clyde and Roxburgh grid-connected hydro power stations, Otago as a region exports a significant quantity of electricity.

9.2 Retail electricity prices in Otago

Retail electricity prices, that would be faced by most of the sites[67], are a reflection of the average wholesale cost of electricity plus the network charges levied by EDBs and Transpower for the use of the existing network. The Electricity Authority publishes the image below showing how the total cost of electricity to a residential household is broken down:

Figure 48 – Components of the bill for a residential consumer. Source: Electricity Authority



[65] By embedded we mean it is connected to the distribution network, rather than connected directly to Transpower's network.

[66] FY22; see https://contact.co.nz/aboutus/investor-centre/reports-and-presentations#Operating-reports

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

However, while all of the components in Figure 48 are also present for large commercial and most industrial consumers, the breakdown will be different, and can vary substantially depending on the size of the facility (in terms of electricity demand), its proximity to a grid exit point, and its location in the country.

In terms of location, the Ministry of Business, Innovation and Employment (MBIE) periodically publishes average domestic (household) electricity prices for 42 locations around the country. This can give us a sense of the cost of electricity in Otago relative to other parts of the country, and the role that the major components in Figure 48 play.

Figure 49 – Quarterly domestic electricity prices in NZ, including GST. Source: MBIE.

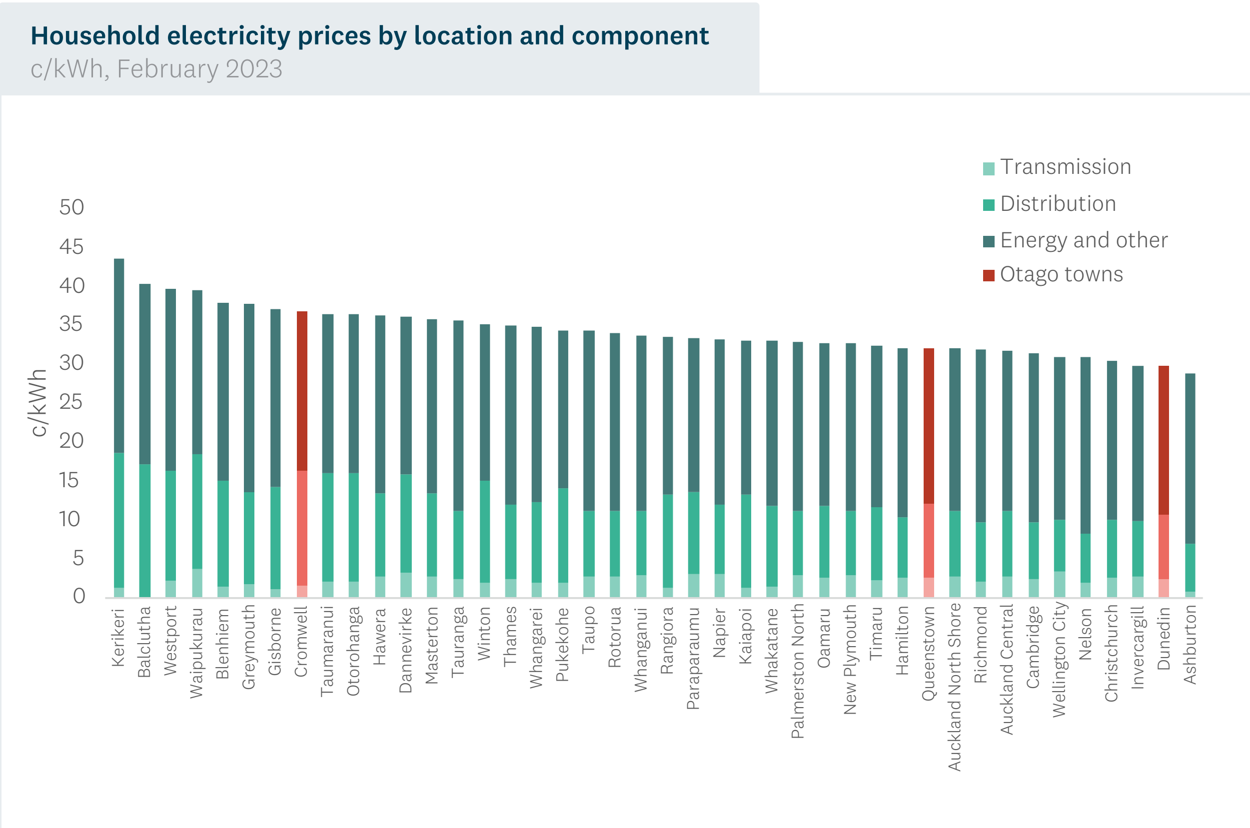


Figure 49 shows that Otago has a spectrum of residential prices, ranging from one of the lowest costs (Dunedin) to one of the more expensive towns (Cromwell)[68]. These differences can occur due to the range in population densities (relative to the geographic size of the region, and thus the size of the distribution network) but also the number of upgrades to Aurora's Central Otago network required in recent years.

[68] Note that "Energy and other" in the chart relates to the generation, retail and other components of Figure 49. The high level of transmission losses will be included in the generation component, rather than the transmission component, which reflect the charges for access to the transmission grid.

These factors will also be present for commercial and industrial electricity consumers, such as potential process heat users considering electric boilers. However, the methodologies that determine the charges paid by commercial and industrial consumers may see these factors manifest differently. This section provides general guidance on the generation, retail, distribution, and transmission components[69], but it is important that process heat users considering electrification engage with electricity retailers and EDBs to obtain tailored estimates relevant to their project.

9.2.1 Generation ('wholesale') prices

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

EECA engaged EnergyLink, an electricity market modelling firm, to use its sophisticated modelling of the electricity market to produce such a price forecast. EnergyLink's model simulates the interaction of wholesale electricity supply and demand, and thus produces wholesale market prices, in a way that closely resembles the mechanics of the actual half hourly market. This includes the way the New Zealand electricity market incorporates transmission losses into the wholesale price observed at each of the ~250 locations (GXPs or GIPs[70]) around the country where power is traded and reconciled. Finally, it also includes the impact of varying inflows into hydro reservoirs, which remains critical given New Zealand's reliance on hydro generation (~55% of total generation) will remain for some time yet[71].

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

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

[70] Grid exit points (where electricity leaves the grid) and grid injection points (where electricity enters the grid from power stations).

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

9.2.2 Retail prices

Most large users of power do not elect to face the half-hourly varying wholesale price, and instead prefer the stability of multi-year retail contracts that contain a schedule of fixed prices, that each apply to different months, days of the week and times of day[72]. Hence the three wholesale price scenarios were adjusted to reflect the observed difference between the wholesale price of power, and how large user retail contracts are typically priced. This is an approximation based on historical evidence but should be a plausible guide (based on historical trends) to what a customer should expect if it sought this type of retail contract. Each site contemplating electrification should engage with electricity retailers to obtain more refined estimates and potential options.

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

- The Energylink price is only forecast for the generation and retail (energy) component[73] of the customer's tariff – that is, they do not include network charges (use of the existing transmission and distribution network, which is in addition to the costs of any upgrades considered above) which will vary from customer to customer. The network component of the bill is discussed further in Section 9.2.4 and 9.2.5.
- Energylink prices include the effects of high-voltage transmission losses to the nearest GXP in the Otago region, but do not include distribution network losses to the customer's premises. Loss factors are set by EDBs companies to account for distribution losses, and these loss factors are applied by retailers to the GXP-based price. In the case of the Otago, distribution losses are very high, due to the long and 'stringy' nature of the grid: the distance from the north to the south of the Otago network is equivalent to the distance between Auckland and Wellington. Hence the distribution losses for sites connecting at 11kV or 22kV typically range between 1.04 to 1.07 for Aurora, and 1.075 for OtagoNet[74].
- Energylink produces prices for four time blocks each month – business day daytime, business day night-time, other day daytime and other day night-time. Different arrangements with a retailer may allow for different granularities of pricing and may also allow for the site to be rewarded for responding to, for example, high wholesale prices by shifting demand (see Section 9.5).

This is a relatively orthodox approach to modelling the electricity tariffs that process heat users may be presented with by their retailers. However, some electricity retailers are evolving their tariffs to provide incentives for large process heat consumers to convert to electricity, and these tariffs have begun to emerge in the New Zealand industry[75]. As part of this RETA analysis, we have incorporated currently available special offers for process heat decarbonisation to be representative of retail prices for the first 10 years of a fuel switching project, after which we revert to EnergyLink's forecasts.

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

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

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

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

9.2.2.1 Scenarios considered

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

- **Low price scenario** – Assumptions that would lead to lower electricity prices compared with the central price scenario, through, for example, lower demand, lower fuel costs, or accelerated[76] build of new power stations.
- **High price scenario** – Assumptions that would lead to higher electricity prices than the Central scenario, for example, higher demand, higher fuel costs or more restrained investment in new power stations.

The three scenarios used are outlined in Table 12 below. More detail on these assumptions is available in EnergyLink's report[77].

Table 12 – Electricity market scenarios considered. Source: EnergyLink

Scenario driver	Central price scenario	Low price scenario	High price scenario
NZAS at Tiwai Pt	Remains	Closes in 2025	Remains
Demand growth[78]	46TWh by 2032; 63TWh by 2048	As for central price scenario but ~5TWh lower from Tiwai exit	50TWh by 2032, 70TWh by 2048
Coal price	USD85/t	USD70/t	>USD100/t
Gas price	Medium	Low	High
Initial carbon price[79]	NZD75/t	NZD75/t	NZD75/t
Generation Investment behaviour[80]	Neutral	Aggressive	Lagged/conservative
Generation disinvestment	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2033	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037

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

[77] EnergyLink (2022), 'Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Programme', May 2022

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

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

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

EnergyLink also model the 'levelised cost of energy' (LCOE) associated with generation investment classes (e.g. wind, solar) into the future[81]. The degree to which these forecasts of LCOE affect investment are then a function of these costs, the way the projects are assumed to be financed, and the cost of debt.

Noting that the low and high price scenarios are not necessarily designed to be the most plausible storylines[82], but instead to apply assumptions that would deliberately lead to high and low-price outcomes. As with many scenario analyses that involve mathematical models, there is a tendency for these models to understate the true range of potential prices as they cannot incorporate all of the real-world factors (including human decision making) that drive price. Thus, EnergyLink's scenarios provide information on what a range of price outcomes might look like. It is also important to note that the low and high price scenarios assume the variables in the table persist every year for 25 years. In reality, the market could periodically 'switch' from one scenario to another and remain there for a number of years.

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

- The scenarios assume that the national electricity system reaches the Climate Change Commission's target of 95% renewable generation by 2030.
- The scenarios have not factored in the proposed pumped storage scheme at Lake Onslow. They do assume that the remaining thermal peaking plant can be switched (if deemed economic) to a low emissions fuel and has fuel storage large enough to support the system through extended periods of low inflows[83].
- EnergyLink applies different inflation assumptions to the various assumptions in the table above, each of which imply different rates of decline from its current level of 7% to a long-term rate of 2%.

9.2.3 Price forecasts

Annual average (nominal) price forecasts are presented below for the period 2026-2048. For the central price scenario, real electricity prices increase by 6% by 2037.

As is shown in Figure 50, the impact of Tiwai's exit (combined with the other assumptions in the low price scenario) is significant. While this is a lower end on the range of prices, other forecasts (e.g. Climate Change Commission) show similar impacts from the Tiwai closure, albeit with shorter duration[84].

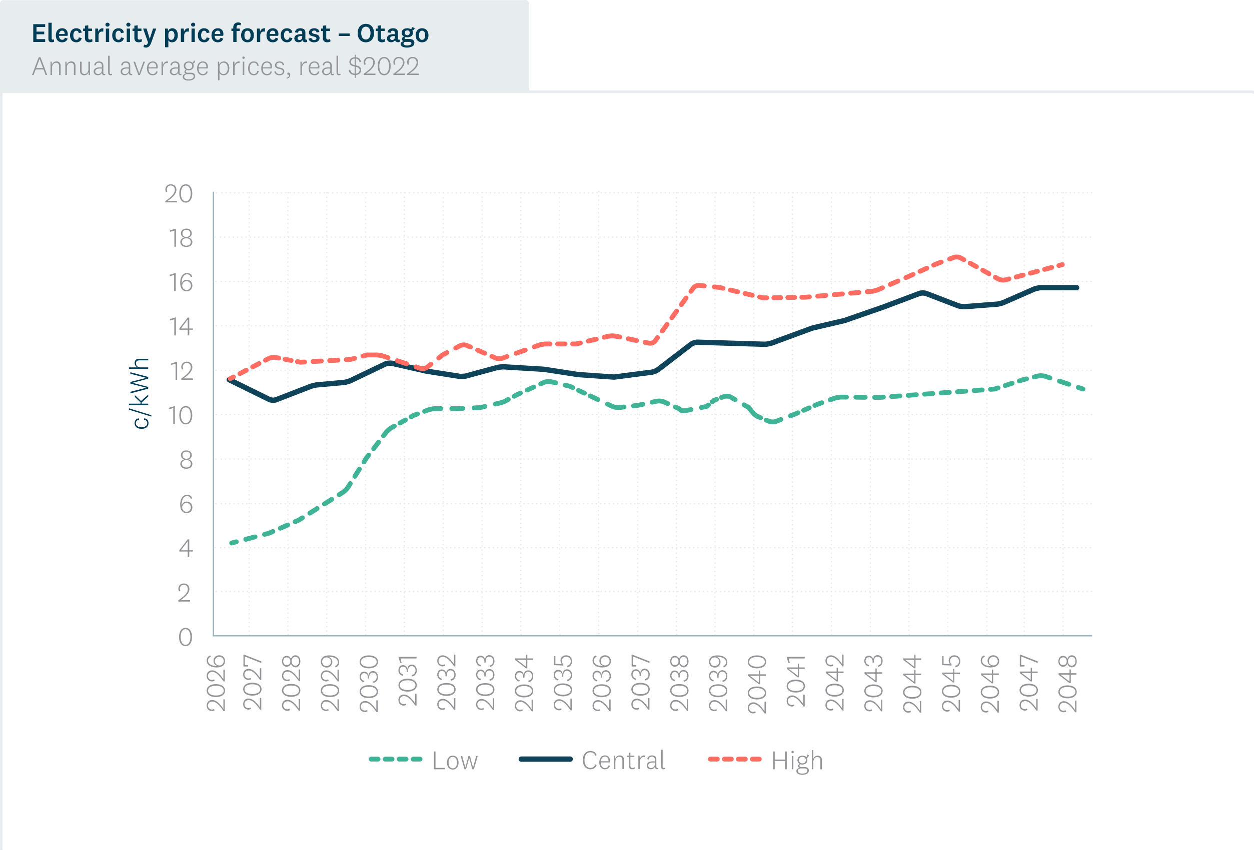
[81] "In real terms, the cost of building, owning and operating new wind generation falls at rates calibrated against actual wind projects in New Zealand, with adjustments for the cost of financing projects. The cost of grid-scale solar farms also falls in real terms, but as there are no such projects in New Zealand, the rate at which costs fall is calculated from a combination of information that is in the public domain in New Zealand, along with data from overseas." EnergyLink, p 14, footnote 20.

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

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

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

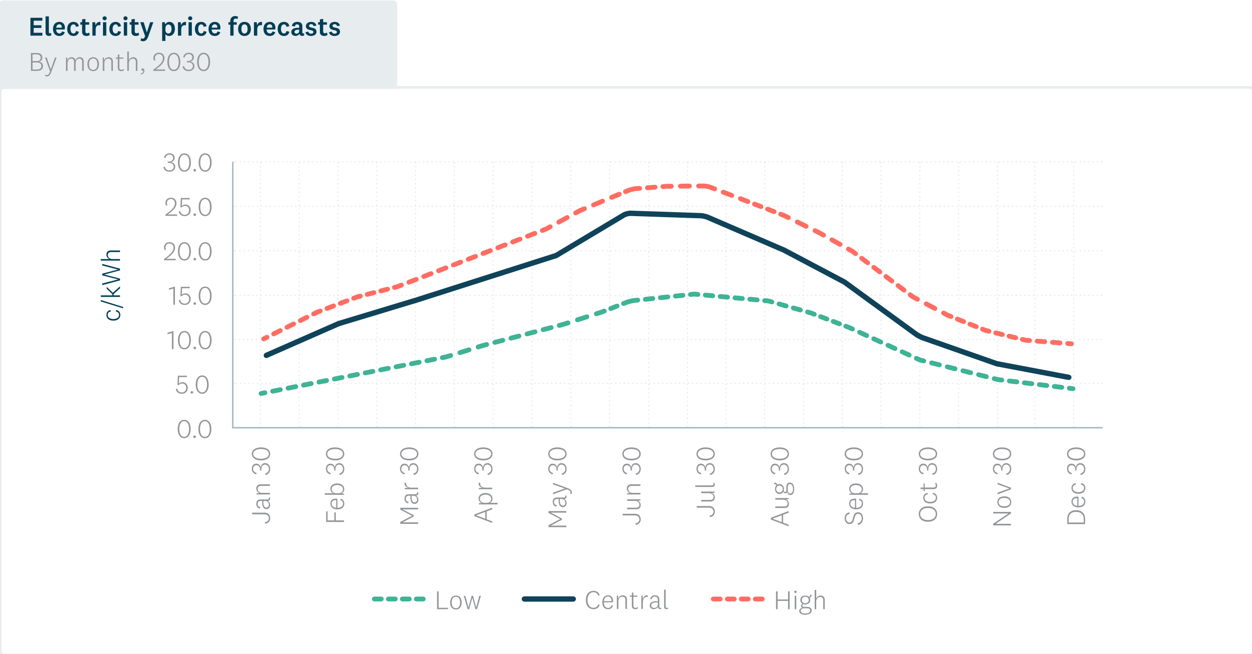
Figure 50 – Forecast of real annual average electricity prices for large commercial and industrial demand on Otago. Source: EnergyLink

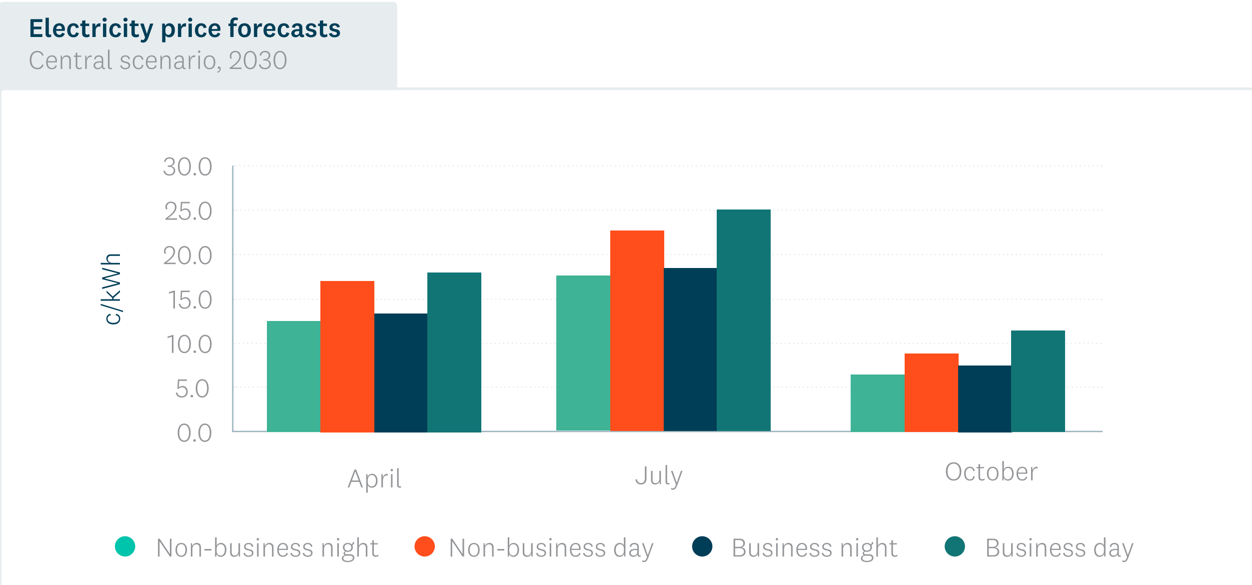


Beyond 2037, this forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond the end of the RETA period. Some New Zealand market analyses suggest real prices may remain constant after 2035, due to the downward pressure on generation costs (especially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

As outlined earlier, the price forecasts are actually produced at a finer resolution than the annual average series in Figure 50. Figure 51 zooms in on 2030, showing (a) the variation over the year in the three scenarios, and (b) the variation between business and non-business days, and time of day.

Figure 51 – Electricity price forecasts (a) by month and (b) by time block in April, July and October 2030. Source: EnergyLink





The shape of electricity prices over the year reflects the expected nature of national winter demand (winter peaking – lighting and heating) coupled with lower winter inflows into alpine lakes. However, this is somewhat inversely correlated with some of the sites considered in this study, particularly dairy, who experience the lowest levels of demand during winter. Hence the volume-weighted price paid for electricity at these sites could be materially different from the annual average prices shown in Figure 50 above.

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

9.2.4 Distribution network charges

EDBs levy charges on electricity customers for the use of the distribution network, except for those large customers who connect directly to one of Transpower's GXPs. As monopolies, EDBs are permitted under the Commerce Act to recover the cost of building and operating the distribution network plus a regulated return. The total amount EDBs can earn is regulated by the Commerce Commission, while the manner in which they charge (generally referred to as 'distribution pricing'[85]) is overseen by the Electricity Authority.

The magnitude of charges for any individual customer depends on each EDB's 'pricing methodology'. This methodology describes how each EDB will convert its allowable revenue into prices for different customer groups, while meeting the principles set by the Electricity Authority for efficient pricing. Each year, these prices – for each customer group – are published by each EDB in a 'pricing schedule'[86].

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

- Fixed daily charges.
- Demand charges – usually related to the highest level of demand reached by the site over a year[87], or the demand level during times when the whole network experiences its highest demand[88] (usually measured in kW or MW).
- Capacity charges – related to the full capacity of the connection provided by the EDB (measured in kVA or MVA).
- Daily distance price (Aurora only) – related to the distance the customer is from the GXP.

These charges – for both distribution and transmission (see discussion in Section 9.2.5) – are summarised in Table 13 below. The charges in the table do not reflect the exact pricing structures each EDB uses – we have approximated the effect of different variables in order to simplify the charges for the purposes of summarising into a single price. Due to significant differences in Aurora's charges across different parts of their network, we have included each region separately.

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

[86] The 2023-24 pricing schedules and methodologies for the two Otago network companies can be found on the websites of Aurora and OtagoNet.

[87] Often referred to as 'anytime maximum demand', or AMD.

[88] Sometimes referred to as 'coincident peak demand'.

Table 13 – Estimated and normalised network charges for large industrial process heat consumers by EDB; $ per MVA per year. Source: EECA analysis

EDB	Distribution charge	Transmission charge	Total charge
OtagoNet	$120,000	$110,000	$230,000
Aurora (Dunedin)	$95,000	$65,000	$160,000
Aurora (Central Otago)	$200,000	$70,000	$270,000
Aurora (Queenstown)	$100,000	$85,000	$185,000

The difference in prices between networks can reflect a variety of characteristics of each network – their pricing methodologies (which determine how costs are allocated between domestic, commercial and industrial consumers), the nature of their network (e.g. proportion of high-density urban environments versus sparse rural areas), and where they are in their investment cycle.

While we provide these indicative levels of charges for process heat users, it is important that each business considering electrification of process heat engages with their EDB to discuss the exact pricing that would apply to them. For the modelling outlined in Section 7, we have developed indicative distribution pricing for each process heat user based on 2023/24 pricing schedules for their relevant EDBs, which in many cases differ materially than the normalised approximate charges in Table 13.

Central Otago, New Zealand. Credit – Aurora Energy.

9.2.4.1 Future changes to distribution prices

When considering a business case for an investment that will last many years, a very important factor is the potential changes in how EDBs might structure their prices, and the degree to which these charges will be reflected in retail electricity contracts[89]. The Electricity Authority is working with EDBs to move their pricing approaches, over time, towards more efficient pricing structures, with five focus areas:

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

More detail is available on the Electricity Authority's website[90].

9.2.4.2 Contributions to the capital cost of accommodating new demand

In Section 9.3, we provide estimates of the capital costs that EDBs (and, for some large users, Transpower) would incur in order to upgrade their network to accommodate a particular process heat user's electrification decision.

The charges in that section are presented as total capital costs. Precisely how the process heat user pays for these upgrades, however, is usually more complex than a simple up-front payment. There are a variety of ways that EDBs can recover these costs (assuming that it is the EDB that constructs the new assets[91]). These ways are presented in the EDB's 'capital contribution' policies. These policies recognise the fact that new demand is subject to the cost-recovery charges outlined above, and hence – over time – a component of the cost of new assets will be recovered through these charges.

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

[90] See https://www.ea.govt.nz/projects/all/distribution-pricing/

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

Hence the EDB may elect to calculate an up-front capital contribution that is only a portion of the total cost of the required upgrades. In some situations, the EDB may design customer-specific charges (often including a larger fixed component than indicated in Table 10 above), tailored to the process heat user's expected demand and location in the network.

The exact methodology used to determine the quantum of capital contribution it requires from new electricity demand varies between EDBs. It is important that process heat users contemplating electrification meet with their EDB to discuss how this will work in their particular situation. For the pathway modelling outlined in Section 7, we assume that EDBs contribute 50% of the capital costs associated with distribution network upgrades required to connect process heat users.

9.2.5 Transmission network charges

Where a consumer connects directly to the grid, Transpower will charge this consumer directly. Otherwise, they are passed through without any markup by the local EDB. This is a topic picked up further below.

The rules governing how Transpower charges its customers (distributors, directly connected industrials and generators) are determined by the Electricity Authority. These rules – known as the Transmission Pricing Methodology (TPM) – have been a contentious topic since Transpower was separated from the Electricity Corporation of New Zealand (ECNZ) in the early 1990s. Over the past 10 years, the Electricity Authority has conducted a number of phases of consultation in an effort to create a more enduring TPM, less subject to litigation.

A major revision to the TPM guidelines was concluded by the Electricity Authority in 2022. These charges come into effect for the 2023/24 pricing year[92]. Alongside the new TPM, the Electricity Authority released guidelines for EDBs around how to pass through the new transmission charges to their customers (which will include the majority of process heat users covered by this RETA)[93].

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

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

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

9.2.5.1 Overview of the Transmission Pricing Methodology (TPM)

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

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

- **Connection charges** – There are some assets owned by Transpower which are only there for the benefit of a very small number of users. These are known as 'connection assets', as they tend to exist solely to connect an EDB's network, and/or a large industrial consumer, and/or a generator, to the national grid. In these situations, Transpower's costs – capital returns and operating expenses – are shared amongst that very small group of users in a relatively simple way.
- **Benefit-based charges (BBC)** – These charges relate to specific investments where the beneficiary identification is more complex than for connection assets[94], but the beneficiaries have been established by the Electricity Authority (and allocations of charges calculated accordingly). This analysis will occur for grid investments going forward, but also includes seven relatively recent grid upgrades that were approved by a regulator under the current market design, and hence were subject to a range of cost-benefit assessments. Should grid upgrades occur in the Otago region (see Section 9.3), the associated transmission charges would be calculated in accordance with the BBC methodology. It is difficult to estimate at this point in time what the likely charges would be, as the Electricity Authority won't determine the allocations amongst the various beneficiaries until the investment is formally considered.
- **Residual charges** – For the remainder of the existing transmission network not covered by BBC charges[95], it is too difficult to identify specific beneficiaries of each asset. Charges for these network assets are referred to as the residual charge (RC) and are spread across all loads (EDBs and grid connected industrial consumers). Generators don't pay the RC. RC is principally spread across loads in proportion to their anytime maximum demand. An important consideration for new grid-connected electricity demands, such as that arising from electrification of RETA process heat sites, is that they do not receive an RC charge for the first four years of operation; after that, the RC allocation steps up linearly over a four-year period.

As a result, these new grid-connected demands (which include demands from distribution networks) do not face their full RC allocation for eight years. Equally, RCs for grid-connected demands take eight years to reduce to the new level.

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

[95] Pre-2019 grid assets, not including the seven relatively recent grid upgrades listed in Appendix A of the TPM.

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

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

- **Transitional Cap** – A transitional cap on prices to avoid 'rate shock'. The cap is inflation adjusted; hence, with prevailing rates of inflation in early 2023, the cap is unlikely to have any material effect on charges.
- **Adjustments to Charges** – Adjustments for things like new connections to the transmission network, customers disconnecting from the transmission network, and substantial changes in circumstance leading to substantial changes in consumption (increased or decreased). This is especially important for the connection of new electrode boilers, which – as they are replacing coal – would in some cases lead to material increases in demand taken by EDBs from Transpower's grid. Equally, some large sites may decide, upon electrification, to switch from being connected to the distribution network to direct grid connection – this would cause a drop in the EDB's peak demand.
- **Prudent discounts** – The TPM provides for discounting transmission charges where, based on an economic framework, a customer is 'overcharged' as a result of the TPM. Overcharging has a specific meaning, namely that the customer's TPM charges would lead them to inefficiently bypass the grid, for example by building a self-supply and disconnecting from the grid, or building a line to a different part of the grid. Transpower has published a draft prudent discount manual. There is a significant amount of analysis that is required in order to prove that an individual customer's TPM charges are a genuine case of 'overcharging'.

We note that, since Transpower is entitled to recover a fixed amount of revenue from its customers, any reduction to one set of Transpower's customers, using the mechanisms above, results in an increase in charges to Transpower's other customers.

9.2.5.2 What does the TPM mean for RETA sites?

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

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

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

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

The EDBs will need to do some form of categorisation and averaging to allocate the transmission charges. The methods used in the TPM for categorising, averaging, and lagging measures of 'usage'[96] of the grid give EDBs some discretion to how costs will fall. For example, an averaging method based on energy consumption will tend to move charges from residential towards industrial consumers and vice versa for averaging based on peak demand[97]. EDBs may also base charges on historical periods that, in their view, are a better reflection of the party's consumption that created the need for transmission capacity in the first place.

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

9.2.6 Pricing summary

In summary, this section has shown that process heat users considering electrification would face the following charges for electricity consumption:

- A retail tariff which would **average around 11c/kWh over the next 15 years**, although the effective average tariff will differ between process heat users depending on the way their consumption varies over the year. Further, industrial process heat users may be able to secure special retail rates being offered by electricity retailers currently, which are significantly lower, in some cases, than 11c/kWh.
- A network charge which comprises components relating to the use of the existing distribution network, and Transpower's transmission network. These charges are structured in a range of different ways, and are specific to the particular part of the network the process heat user is in. We have approximated the published charges of Aurora and OtagoNet on a common per-MW (installed capacity) basis, suggesting the combined distribution and transmission charge **could vary between $160,000/MW and $270,000/MW per year**. However, we strongly recommend process heat users engage with the relevant EDB to obtain pricing that is specific to their location, operating profile and desired capacity.

The next section considers the third component of costs, which is the potential for RETA sites to need upgrades to the distribution network in order to accommodate the electrification of their process heat. This would require a capital contribution from the process heat user.

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

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

9.3 Impact of process heat electrification on network investment needs

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

Further, accommodating new demand for electricity from process heat is not purely a matter of building new network assets. The degree to which network expansion is required can be influenced by the process heat user's willingness to be flexible in *when* they consume electricity and/or their willingness to have supply briefly interrupted on those very infrequent occasions when a network fault occurs. As outlined in Section 9.5, there are a range of ways that process heat users can benefit from being flexible, and EDBs are exploring ways in which customer response can be reliably integrated into their networks via operational arrangements and pricing incentives[98].

These opportunities are not included in Ergo's assessment of connection costs, and process heat users should engage with their EDB early to understand how their use of flexibility can reduce the cost of connecting, and what the operational implications are.

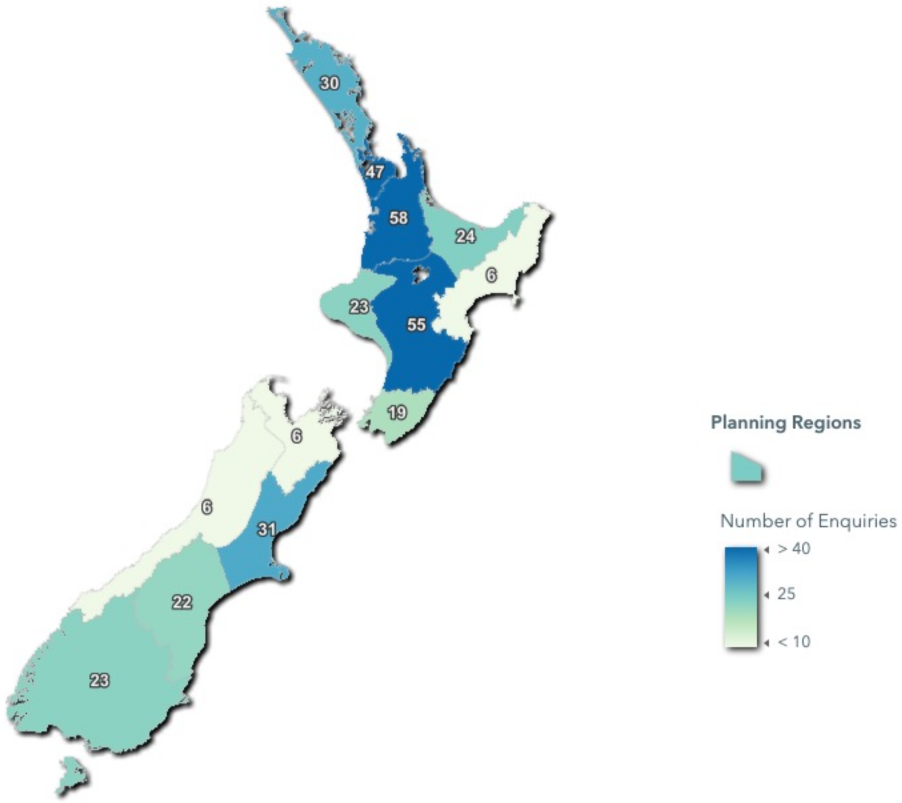
We stress that the assessment of spare network capacity, costs, and lead times presented below is changing all the time. The policy and regulatory space for the electricity sector is in a state of change as it incorporates decarbonisation and the emergence of new technologies. This in turn is leading to a greater number of consumers considering the technology they buy and how they reduce their consumption of fossil fuels. Hence Transpower and EDBs exist in a context which is changing far more quickly than it did, say, 20 years ago.

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

[98] This is part of a broader development of 'non-network alternatives' by EDBs and Transpower – demand response from consumers, distribution-scale batteries, and distributed generation – to defer the need for more capital-intensive upgrades.

As an illustration of this, Figure 52 below shows the number of enquiries Transpower alone is facing in each of its planning regions. Of the 350 enquiries they face nationally, 72% have need dates prior to 2025[99]. Transpower reports that of the 42[100] enquiries in Otago-Southland, a third are for network upgrades or process heat connections, the remainder are for generation connections.

Figure 52 – Number of grid connection enquiries per region, June 2023. Source: Transpower



It is going to be challenging for Transpower and EDBs to scale up their resourcing to cater to this new demand.

The implication for the material presented in this section is that it is a snapshot in time, in an electricity industry that is rapidly changing – both on the supply (generation) side, and for consumers as they consider electrification.

[99] As at May 2023.

[100] The regional figures on Transpower's map exclude any enquiries that are only prospects, commissioned, or "enquiries… that have been assessed as unlikely to proceed to commissioning". Our figures in the text report the total number of enquires.

9.3.1 Non-process heat demand growth

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

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

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

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

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

9.3.2 Network security levels N and N-1

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

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

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

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

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

- **N-1 security** – Where N-1 security is present, forecast peak demand can be met and, furthermore, any ‘credible’ failure of a single component of the network (e.g. transformer or circuit) will also leave the system in a satisfactory state.[101]
- **N security** – A failure of any single component of the network at forecast peak demand may result in a service interruption that cannot be restored until the fault is repaired.

N-1 is typically provided through building redundancy into network assets, relative to the expected (peak) demand.

Generally, N-1 is the standard that applies on the ‘interconnected’ parts of Transpower’s high-voltage transmission grid, due to the scale of bulk power flows affecting a large part of the population. However, on some more remote parts of Transpower’s grid, the economic trade-off between N-1 and the cost to local consumers of the investment to accommodate demand growth may mean lower security is more efficient, and/or there are other ways to provide N-1 (see below) and better balance affordability.

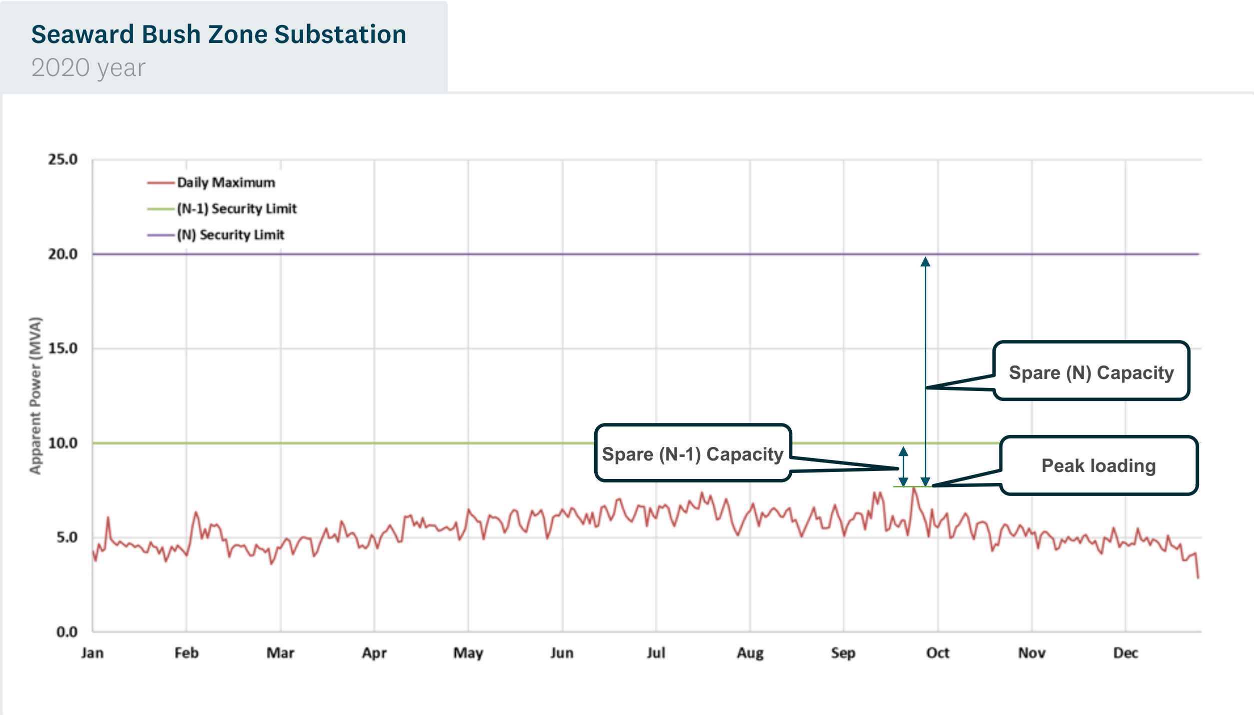
In the distribution networks, the lower scale, coupled with higher network density, means providing the redundancy for N-1 to every customer would be very expensive. Hence, many parts of the distribution network only experience N security. Some EDBs also use a concept of ‘switched’ security, where the EDB responds to a network event by switching a customer across to an alternative network asset. This switching may result in a short interruption, which may or may not suit the customer.

The extent to which an EDB provides (or preserves, in the face of increasing demand) N-1 is a risk-based assessment which considers, amongst other things, the proportion of time that a particular part of the network would exceed N-1 capacity; the economic and risk profile of the existing customers; and the trade-off between the costs of extra capacity versus increased risk of interruption. For this reason, N-1 is often provided by EDBs in urban areas where there is high density of households and businesses. Approaches to determining where N-1 will or won’t be provided are typically detailed in the EDB’s asset management plans (available on their websites). Process heat users should engage with their EDB to determine how this applies to their site.

Figure 53 illustrates the difference between the available capacity for N and N-1 security for a zone substation.

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

Figure 53 – Illustration of spare N and N-1 security capacity at Seaward Bush zone substation. Source: Ergo



If a customer agrees with the EDB to utilise N security capacity[102], there may be operational measures that would need to be put in place to ensure network security is managed in the event of a network fault. These operational measures will likely include a physical arrangement which automatically interrupts supply to the process heat user when a network fault occurs.

For the purposes of this report, Ergo determined the amount of spare capacity by using Transpower's prudent peak demand forecast[103] for the coming year (2023), rather than actual observed peak demand as inferred by Figure 28 above. The use of a prudent forecast recognizes that there are a range of variables that can determine what happens on a given day or time, such as weather and the decisions of individual consumers which may see a drop in load diversity for a short time.

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

[102] This includes situations where N-1 security is currently being provided to existing customers (often the case in urban centres), but the connection of a new process heat demand exceeds the spare N-1 capacity. In order to continue providing N-1 security to existing customers, an arrangement between the new process heat user and the EDB could be that the new process heat user uses spare N capacity on the understanding that the EDB can automatically interrupt supply in the event of a network fault. This ensures that continuity of supply (i.e. N-1) is maintained to the existing customers, whilst at the same time limiting the investment required to accommodate the new process heat user.

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

9.3.3 Impact on transmission investment

The electrification of the RETA sites will increase the electricity demand at five of the six Otago GXPs shown on Figure 47 above (Naseby does not have any potential RETA sites). Two of these GXPs, and the connecting grid lines, have very little spare N-1 capacity remaining. This is summarised in Figure 54. For the avoidance of doubt, Figure 54 shows the capacity *headroom* at each GXP, that is, the difference between Transpower's prudent demand forecast (for 2022) and the N or N-1 capacity at the GXP (as published by Transpower). A negative value for spare N-1 capacity, as shown for Halfway Bush, reflects the fact that Transpower's prudent peak demand forecast *exceeds* the N-1 capacity of the GXP – that is, the GXP will effectively be experiencing N security at that level of demand.

Figure 54 – Spare capacity at Transpower's Otago grid exit points (GXPs). Source: Ergo

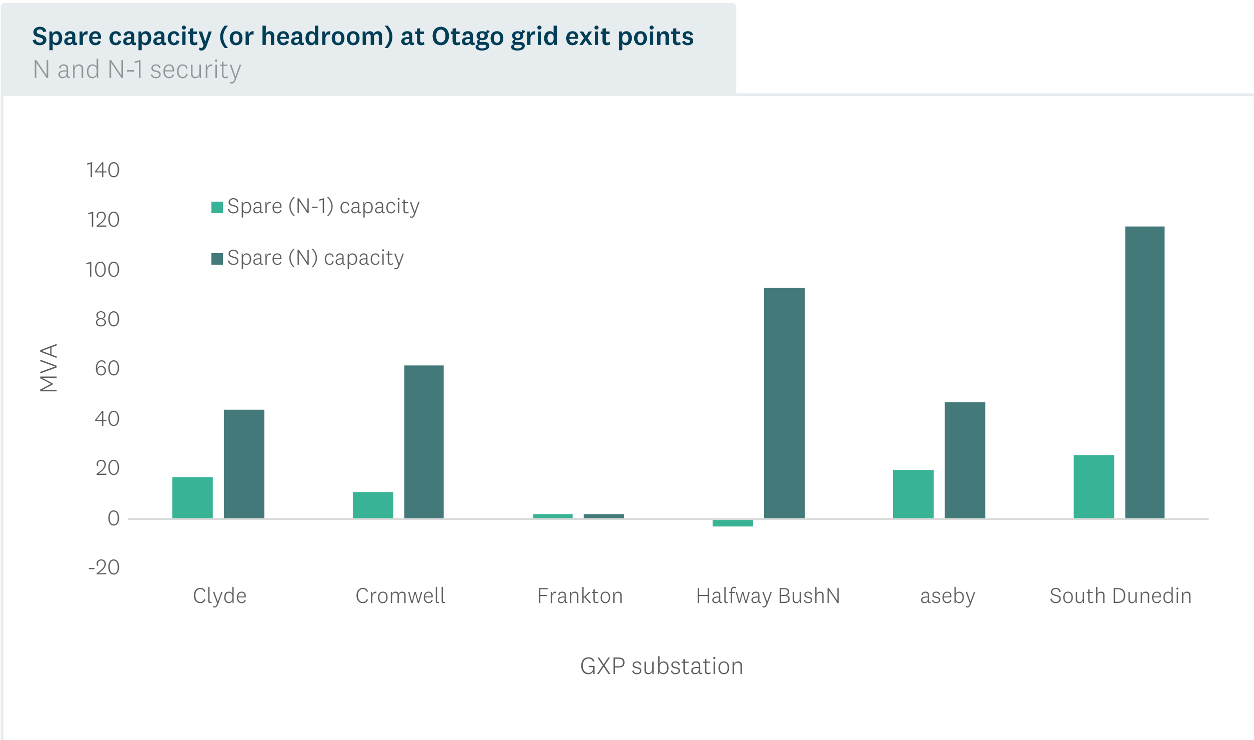


Figure 54 infers that there are modest levels of spare N-1 capacity at Clyde, Cromwell, Naseby and South Dunedin. Again, using Transpower's 2022 forecast demand, there is no spare N-1 capacity at Halfway Bush, but a significant amount of N. Aurora Energy also has the capability to shift approximately 20MW of demand relatively quickly between Halfway Bush and South Dunedin GXP. Spare capacity at Frankton is very limited for both N and N-1 security.

We note that spare capacity at Halfway Bush is complicated by the presence of significant embedded generation – particularly the 36MW Mahinerangi wind farm and 38MW from the Waipori hydro station[104]. Insofar as these stations are generating at the time that peak demand occurs at the Halfway Bush GXP, the embedded generation will reduce the demand on Transpower's assets. However, this generation is not 'firm', in the sense that the reducing effect on the GXP will depend on wind and hydrology at the time. In forming its demand forecast for Halfway Bush, Transpower assumes no contribution from embedded generation, a prudently conservative position. However, this does lead to an expectation (from a prudent forecasting perspective) that peak demand at Halfway Bush will exceed the N-1 security at the GXP (hence the negative value showing in Figure 54).

For those sites with limited spare capacity left, we comment below on any planned transmission upgrades[105]. These are summarised in Table 14.

Table 14 – Spare grid exit point (GXP) capacity in Otago and Transpower's currently planned grid upgrades.

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Clyde	Aurora	Dunstan Hospital	Moderate	None
Cromwell	Aurora	Fulton Hogan Cromwell Asphalt Plant	Moderate	Transpower, Aurora and PowerNet investigating options that will jointly improve Cromwell and Frankton N-1 and voltage stability. These include: • Transformer upgrade at Frankton substation (confirmed) • Transmission line uprating from Cromwell-Frankton (possible) • 33 kV cable uprating at Cromwell (possible) • 33kV outdoor to indoor conversion at Cromwell (possible) • 220/110/33 kV transformer upgrade at Cromwell (possible)
		Cromwell Pool		
		Cromwell College		
		Mt Aspiring College		
		Cromwell EV Charging Station		
Frankton	Aurora	Southern Lakes Laundries	None	
		Lakes Leisure		
		Queenstown Primary School		

[104] To be clear, these stations share a connection between Halfway Bush and Berwick GXPs.

[105] These are upgrades that are specifically planned by Transpower in their 2022 Transmission Planning Report (TPR). Future potential upgrades are also contemplated by the TPR, and may be the subject of discussions with EDBs, but are not costed or formally planned.

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Halfway Bush	Aurora	Oceana Gold Macraes	None	No plans to upgrade the supply capacity at Halfway Bush – Transpower and their customers expect the embedded generation at the Halfway Bush 33 kV will be available and sufficient to provide security to the load for the forecast period. Aurora Energy also has the capability to shift approximately 20MW of demand relatively quickly between Halfway Bush and South Dunedin GXP.
		Fulton Hogan Logan Point Quarry		
		Fulton Logan Dunedin Bitumen Plant		
		Goodman Fielder Dunedin		
		Greggs Coffee		
		Graymont Makareao		
		Lion Emerson's Brewery		
		Keep it Clean Dunedin		
		Keep it Clean Silverstream		
		Moana Pool		
		Mercy Hospital		
		Balaclava School		
		Brockville School		
		Kaikorai School		
		Logan Park High School		
		Otago Boys High School Hostel		
		Ravensbourne School		
		Taieri College		
		Wakari Hospital		
South Dunedin	Aurora	Alsco Dunedin	Moderate	No
		Otago Polytechnic Dunedin Campus		
		Dunedin Energy Centre		
		Dunedin Hospital		
		University of Otago Dunedin Campus		
		Lion Speights Brewery		
		Preens Drycleaners Dunedin		
		Burns House		
		Tainui School		

Assessing the transmission grid implications of connecting RETA sites against current spare capacity is thus only part of the story:

- In some of the cases above where no spare capacity exists today, the planned upgrades in Table 14 will accommodate the connection of new electrified process heat users.
- At GXPs where there are no planned upgrades, the connection of multiple RETA process heat sites may be so significant that an upgrade – not currently planned by Transpower – is triggered.
- There may be some situations where there is insufficient spare N-1 capacity, but a process heat user may be able to either connect at N security – requiring it to be able to reduce demand should a contingency occur – or be able to reduce its demand at peak times so as to avoid breaching the existing N-1 limit. This is covered further in Section 9.5.

For Otago, Ergo's analysis concluded that no individual RETA site, by itself, will trigger the need for a transmission upgrade (although two potential zone substation upgrades are identified). Section 9.4 considers whether the collective connection of a number of RETA sites may lead to a need for transmission investment[106].

9.3.4 Analysis of impact of individual RETA sites on EDB (distribution) investment

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

It is important to emphasise that the analysis undertaken here is preliminary and not intended as a detailed guide to the scope of works required to connect each site. The intended purpose is to provide a high-level 'screening' of process heat sites and the likely magnitude and complexity of their connection arrangements, should they choose to electrify. Further, the connection costs below approximate the total capital cost of constructing the connection assets, which may overstate the cost faced by the process heat user due to the potential for capital contributions from the EDB. It is imperative that process heat owners seek more detailed assessments from the relevant EDB (and potentially Transpower) should they wish to investigate electrification further, or develop more robust budgets[107].

[106] Where grid upgrades are triggered by the collective decisions of multiple organisations (potentially generators and consumers), it falls into the realm of the TPM, which is discussed more in detail in Section 9.2.5 above.

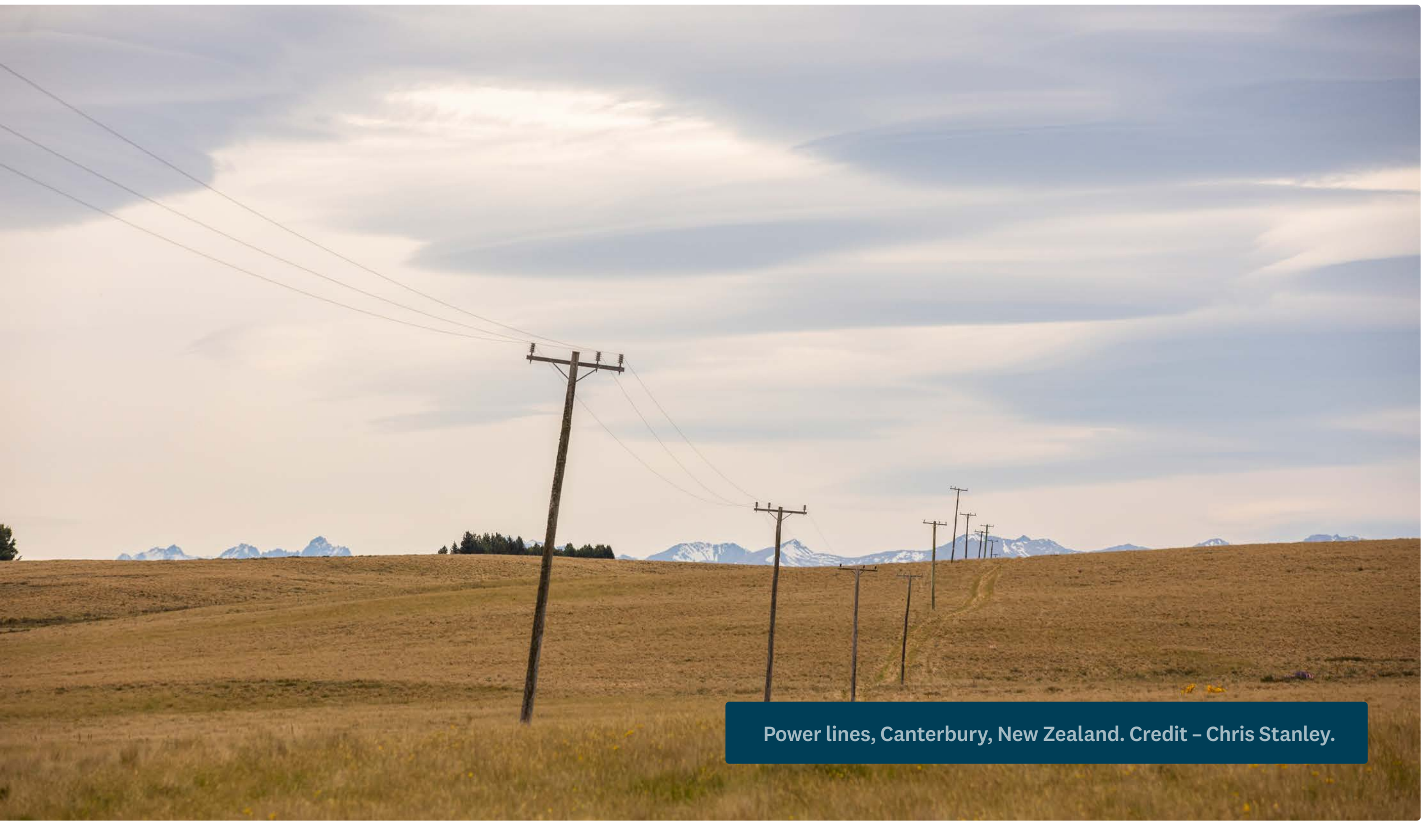
[107] Cost estimates have a Class 5 accuracy – suitable for concept screening. See https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

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

- **Minor** – The 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Some connections may require infrastructure which takes additional time to procure from international suppliers or implement (e.g. transformers, underground cabling).
- **Moderate** – The 'as designed' electrical system requires some infrastructure upgrades including new connections into the local zone substation, upgrades at the local zone substation, and/or upgrades to the sub-transmission[108] 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.

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

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



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

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

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

- Confirm the spare capacities of both the GXP and Zone substations[109]. The analysis presented here calculated these based on the **publicly disclosed loading and capacity information** in Transpower's 2022 Transmission Planning Report and the EDBs 2022 Asset Management Plans.
- The degree to which the process heat user's demand is **coincident with peak demand on the network**, for the purposes of assessing the amount of spare capacity each site absorbs. More detailed modelling of the pattern of site demand, and potential flexibility in that pattern, versus the timing of (typical) peak loadings on the network, may yield further opportunities to reduce upgrade costs. Further, the opportunity for the site to provide short-term demand response (e.g. by utilising hot water storage to pause boiler operation for a small number of hours) in peak demand situations or following a network fault should be considered, as this may have a material impact on cost.
- **The current level of network security to the site, and whether that should be maintained**. The analysis below assumes that, for example, if the site currently has (N-1) security, infrastructure upgrades are recommended to maintain this. Ergo's report[110] highlights where upgrade costs could be reduced by allowing for a lower level of security. Adopting a lower level of security should be considered in consultation with Transpower and the EDB, but enabling the site to provide flexibility (i.e. rapid reduction) in demand in response to a failure on a network[111] could save significant amounts of money where expensive upgrades are required to maintain N-1 security.
- The extent to which the upgrades are affected by the decisions of **other process heat sites regarding electrification in a similar part of the network**. There are some parts of the transmission and distribution network where the collective effect of different upgrades and costs would be optimal should a number of sites simultaneously decide to electrify, or – more practically – coordinate their decisions in a way the gives the network owner confidence to invest. In Section 9.4, we consider the collective impact on a GXP should a number of sites choose to electrify.
- The costs associated with **land purchase, easements and consenting for any network upgrades**. These costs are difficult to estimate without undertaking a detailed review of the available land (including a site visit) and the local council rules in relation to electrical infrastructure. For example, the upgrade of existing overhead lines or new lines/cables across private land requires utilities to secure easements to protect their assets. Securing easements can be a very time consuming and costly process. For this reason, the estimates for new electrical circuits generally assume they are installed in road reserve and involve underground cables in urban locations and overhead lines in rural locations. As a general rule, 110kV and 220kV lines cannot be installed in road reserve due to width requirements. In some locations the width of the road reserve is such that some lines cannot be installed. This issue only becomes transparent after a preliminary line design has been undertaken.

[109] Zone substations are large substations within the distribution network.

[110] See Ergo (2023) www.eeca.govt.nz/assets/EECA-Resources/Co-funding/Otago-Spare-Capacity-and-Load-Characteristics-report.pdf

[111] The most common way to do this is a 'special protection scheme' whereby the network owner allows demand to exceed N-1 on the condition that, should a fault occur, demand is quickly (automatically) reduced down to the N-1 limit.

- The estimates of the **time required to execute the network upgrades**. The estimates below exclude any allowance for consenting and landowner negotiations and are based on Ergo's experience. There is likely to be significant variance depending on the scope of the project and the appetite for expediting.

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

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

Table 15 lists the connections that are categorised as 'minor' in nature.

Cromwell, Otago, New Zealand. Credit – Aurora Energy.

Table 15 – Connection costs and lead times for minor complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak site demand (MW)	Total cost[112] ($M)	Timing
Dunstan Hospital	Clyde	Clyde/Earnsclaugh	0.11	$0.00	3-6 months
Cromwell Pool	Cromwell	Cromwell	0.07	$0.00	3-6 months
Cromwell College	Cromwell	Cromwell	0.16	$0.00	3-6 months
Mt. Aspiring College	Cromwell	Wanaka	0.15	$0.00	3-6 months
Southern Lakes Laundries	Frankton	Frankton	0.90	$0.10	6-12 months
Lakes Leisure	Frankton	Frankton	0.11	$0.00	3-6 months
Queenstown Primary School	Frankton	Queenstown	0.14	$0.00	3-6 months
Goodman Fielder Dunedin	Halfway Bush	Kaikoura Valley	1.18	$0.05	6-12 months
Lion Emerson's Brewery	Halfway Bush	Ward Street	0.83	$0.56	6-12 months
Moana Pool	Halfway Bush	Smith Street	0.28	$0.00	3-6 months
Mercy Hospital	Halfway Bush	Halfway Bush	0.37	$0.00	3-6 months
Balaclava School	Halfway Bush	Kaikoura Valley	0.02	$0.00	3-6 months
Brockville School	Halfway Bush	Kaikoura Valley	0.04	$0.00	3-6 months
Kaikorai School	Halfway Bush	Halfway Bush	0.12	$0.00	3-6 months
Logan Park High School	Halfway Bush	Ward Street	0.30	$0.00	3-6 months
Otago Boys High School	Halfway Bush	Smith Street	0.16	$0.00	3-6 months
Ravensbourne School	Halfway Bush	Ward Street	0.02	$0.00	3-6 months
Taieri College	Halfway Bush	East Taieri	0.35	$0.00	3-6 months
Wakari Hospital	Halfway Bush	Halfway Bush	0.22	$0.00	3-6 months
Alsco Dunedin	South Dunedin	North City	1.92	$0.05	6-12 months
Dunedin Hospital	South Dunedin	North City	2.31	$0.05	6-12 months
University Otago Dunedin Campus (1.73MW option)	South Dunedin	North City	1.73	$0.05	6-12 months
Burns House	South Dunedin	North City	0.17	$0.00	3-6 months
Tainui School	South Dunedin	Anderson Bay	0.12	$0.00	3-6 months

[112] We reiterate that these costs do not include costs associated with the installation of distribution transformers/switchgear on the site. These costs are included as part of the assumed overall capital cost of boiler installation (see Section 7.1).

A number of the smaller sites in Table 15 are shown to have zero connection costs. Ergo's report[113] indicates the expected cost of new distribution transformers for these smaller sites. However, EECA's analysis assumes the cost of distribution transformers are included as part of the ancillary electrical costs of the installation of the boiler (see Section 7.1), rather than as part of the connection costs considered here.

Table 16 lists the connections that are categorised as 'moderate'. There were no connections categorised as 'major'.

Table 16 – Connection costs and lead times for moderate complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak MW	Total cost ($M)	Timing
Fulton Hogan Cromwell Asphalt Plant	Cromwell	Cromwell	9.60	$7.26	18-24 months
Cromwell EV Charging Station (3.8MW option)	Cromwell	Cromwell	3.80	$1.10	12-18 months
Oceania Gold Macraes	Halfway Bush	Golden Point	4.80	$2.10	18-24 months
Fulton Hogan Logan Point Quarry	Halfway Bush	Ward St	4.80	$1.70	12-18 months
Fulton Hogan Dunedin Bitumen Plant	Halfway Bush	Ward St	2.59	$0.90	12-18 months
Greggs Coffee	Halfway Bush	Kaikoura Valley	2.72	$0.90	12-18 months
Graymount Makareao	Halfway Bush	Ward St/ North CIty	7.84	$6.60	18-24 months
Keep It Clean Dunedin	Halfway Bush	Green Island	4.06	$1.38	12-18 months
Keep It Clean Silverstream	Halfway Bush	Mosgiel	4.25	$1.30	12-28 months
Otago Polytechnic Campus	South Dunedin	North City/ Ward St	1.53	$1.06	12-18 months
Dunedin Energy Centre	South Dunedin	North City	7.16	$0.18	12-18 months
University of Otago Dunedin Campus (2.86MW option)	South Dunedin	North City	2.86	$0.66	12-18 months
Lion Speights Brewery	South Dunedin	South City	4.54	$0.58	12-18 months
Preens Drycleaners Dunedin	South Dunedin	South City/ St Kilda	1.96	$1.78	12-18 months

As noted above, none of the individual RETA sites – by themselves – triggered the need for a transmission upgrade.

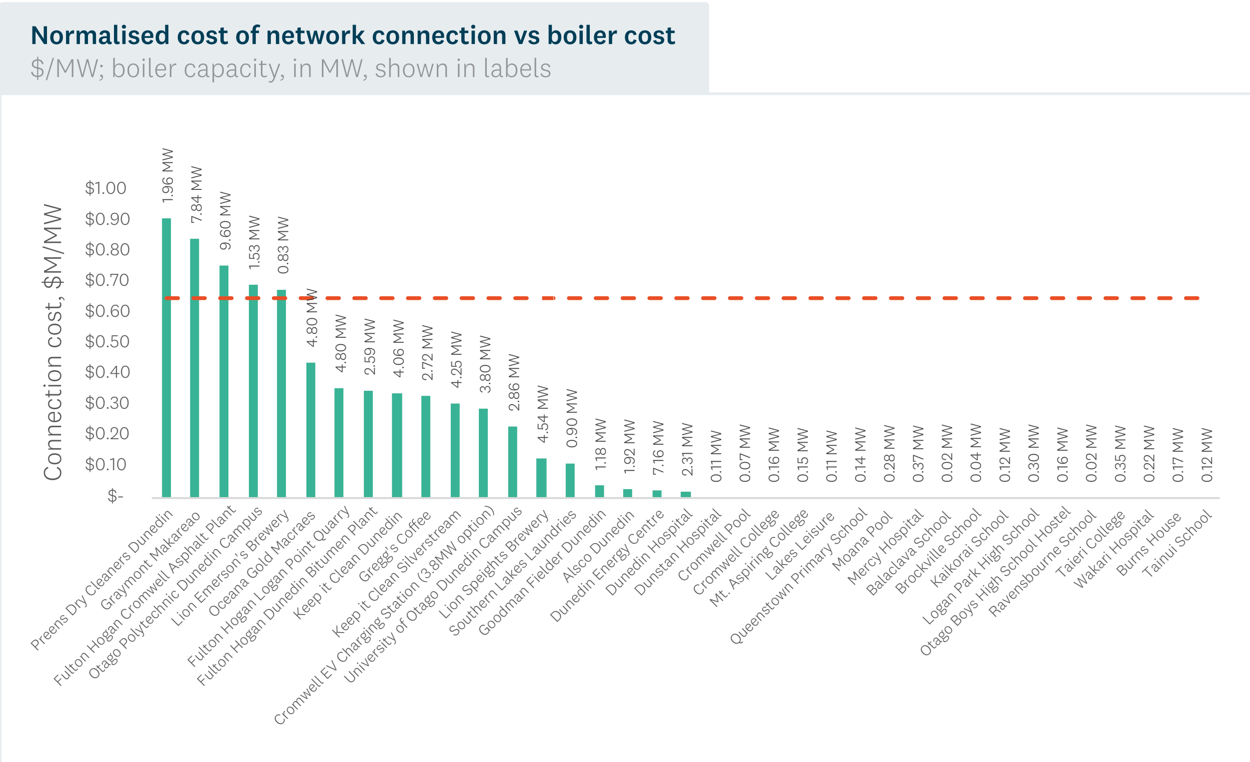
Below, we consider the impact on the need for more substantial upgrades should a number of these minor complexity, at an individual GXP, choose to electrify their process heat.

[113] See Ergo (2023) www.eeca.govt.nz/assets/EECA-Resources/Co-funding/Otago-Spare-Capacity-and-Load-Characteristics-report.pdf

9.3.5 Summary

The network connection costs presented above vary in magnitude. It is worth viewing these costs through the lens of the size of the boiler installation. Figure 55 shows each site's connection costs expressed in per-MW terms – that is, relative to the capacity of the proposed boiler.

Figure 55 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA



The red dashed line in Figure 55 compares these per-MW costs to the estimated cost of an electrode boiler ($650,000 per MW[114]). The figure shows not only a wide variety of relative costs of connecting electrode boilers, but that for five cases, the connection cost more than doubles the overall capital cost associated with electrification. However, as explained above, the connection costs developed in this section, and used in Figure 56, may not reflect the capital costs incurred by the process heat user. EDBs may only charge the user a share of these costs, as per each EDB's capital contributions policies.

While the estimates of connection costs provided here are of an accuracy commensurate with this screening analysis, it does demonstrate how connection costs can have a significant effect on the final decision. It also shows that, particularly for smaller electrification projects, reductions in connection cost of only $50,000 could have a significant effect on the economics of fuel switching decisions.

[114] This is the estimate used in the development of the marginal abatement costs and pathways presented in Section 7.

9.4 Collective impact of multiple RETA sites connecting

The above analysis considered each site in isolation from each other, and whether it could fit into the spare capacity available in existing network infrastructure. This may underestimate the need for wider network upgrades, should a number of RETA sites choose to electrify and therefore – collectively – have a more significant impact on peak network demand.

9.4.1 Diversity in demand

In considering scenarios where multiple sites electrify their process heat and connect to common network infrastructure, we must first consider what the resulting collective peak demand is. A simplistic approach would be to sum the individual peak demands of each RETA site, and add them to the existing peak demand on the network. However, RETA sites may have quite different patterns of demand over the year – some peak in winter (swimming pools, schools) while others (e.g. dairy) peak in summer. In other words, not all individual site 'peaks' happen at the same time. Further, they may not occur at the same time as the existing demand peaks. Hence a better approach is to consider the diversity in the operational requirements of each RETA site, which may see each site:

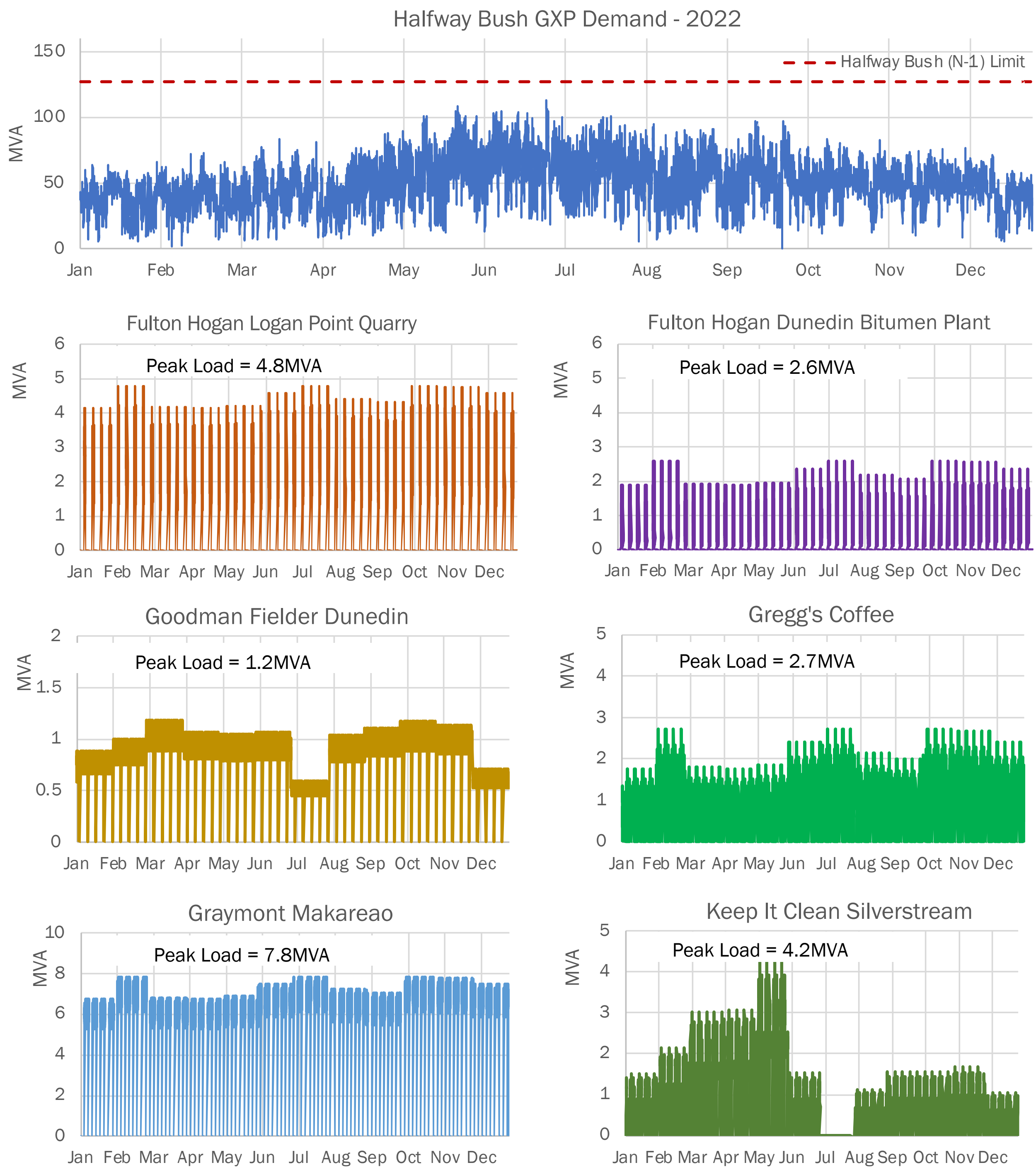
- Reach its peak demand at a different time to the other RETA sites.
- Reach its peak demand at a different time to existing network demand.

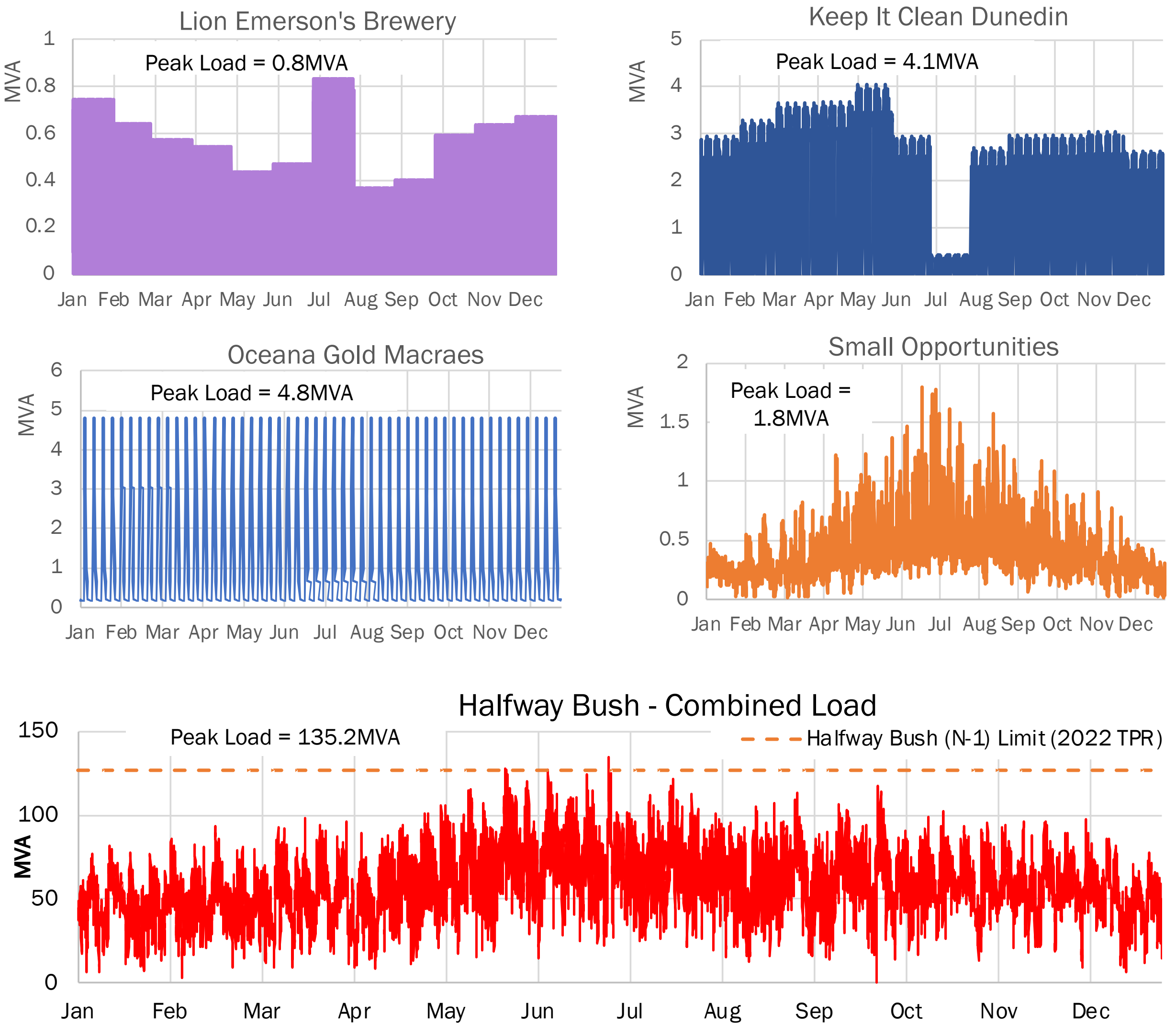
If we can simulate the operational profiles of each site, we can approximate the extent to which diversity in peak demands leads to a lower overall peak demand on the network than the simple addition of each site's peak.

Determining the collective impact on peak demand requires detailed data on the profile of existing demand over the year, as well as similarly detailed data for each individual RETA site. Ergo obtained half hourly historical demand data for each Otago GXP for 2022, as well as simulated individual site profiles based on other similar sites. This allowed a simulation of what half-hourly demand at each GXP would have looked like in 2022, had all RETA sites been electrified.

Figure 56 illustrates this approach for the Halfway Bush GXP. The top chart shows the half hourly demand at Halfway Bush over the 2022 year. Below that, we show the simulated half-hourly demand profile of each RETA site, should they choose to electrify their process heat. The bottom chart shows the simulated resulting demand at Halfway Bush, should these sites electrify their process heat. We reinforce that this more detailed analysis is a simulation based on 2022 data, hence is only indicative of the collective effect of these sites connecting, as though that happened in 2022. A more robust analysis would require consideration of future changes to half-hourly demand at Halfway Bush, including underlying growth from sources other than RETA sites.

Figure 56 – Simulation of impact on Halfway Bush GXP demand from all RETA site electrification. Source: Ergo



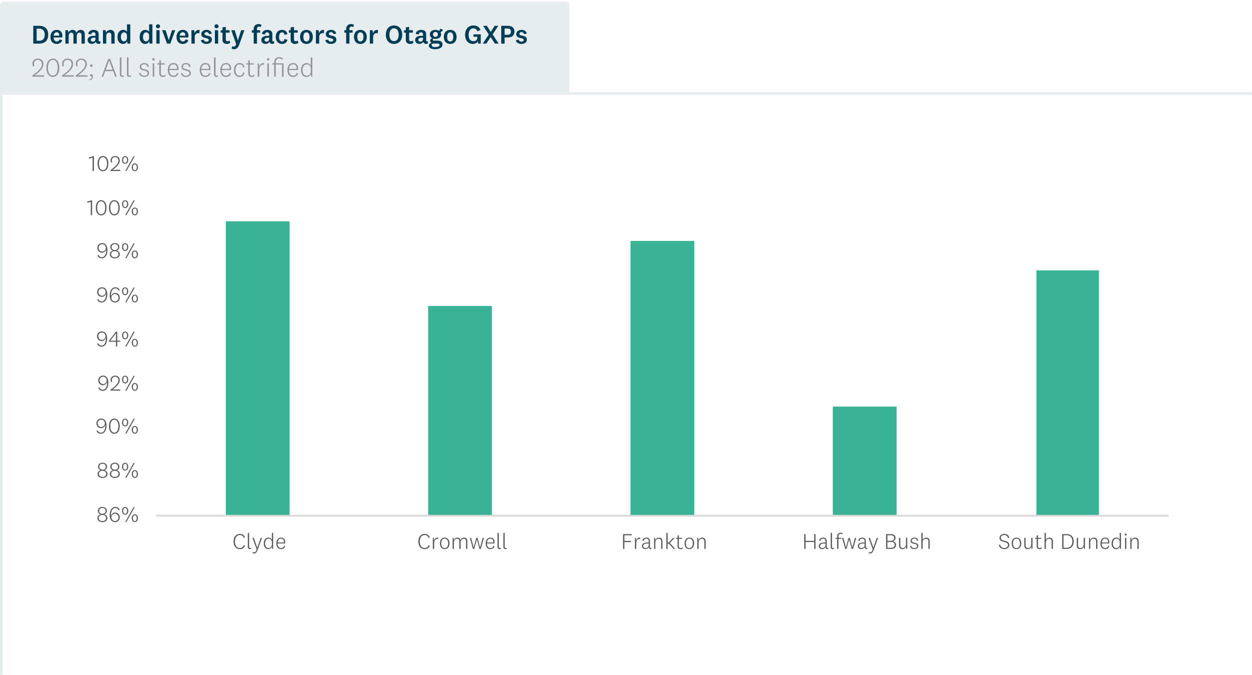


Importantly, the resulting peak GXP demand observed in mid-June is 135MVA[115], which is lower than the simple addition of all individual RETA site peaks (35MVA) to the 2022 Halfway Bush peak demand (113MVA), which would have suggested the new peak is 148MVA. The effect of demand diversity amongst the different Halfway Bush RETA sites is that the combined peak is 91% of what a simple addition would have suggested. We refer to this as a diversity 'factor'.

Ergo repeated this analysis across all GXPs. The resulting demand diversity factors are shown in Figure 57.

[115] Here we use mega-volt-ampere (MVA) as the unit of demand. The analysis above has used mega-watts (MW) as the more conventional unit of demand. The difference between the two relates to accounting for reactive power. In most cases the difference is minor.

Figure 57 – Demand diversity factors for Otago GXPs. Source: Ergo

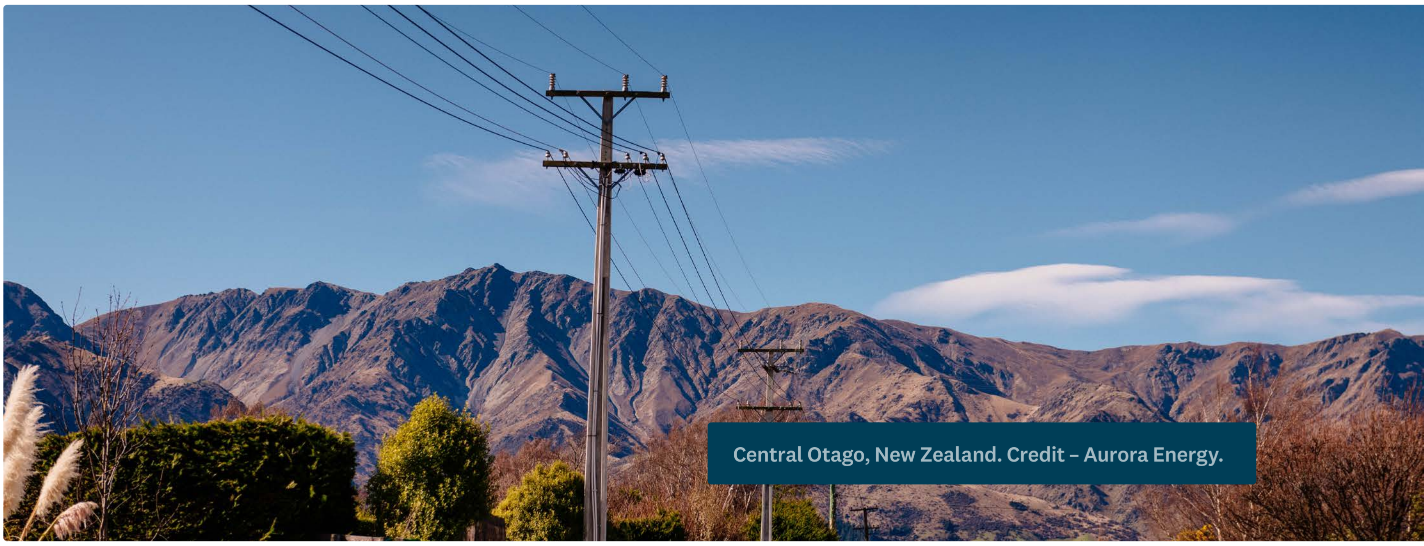


9.4.2 Assessment against spare capacity

We can use these diversity factors to determine the impact of all sites electrifying on spare capacity. Figure 58 shows the amount of spare capacity at each GXP if that would be used under two scenarios:

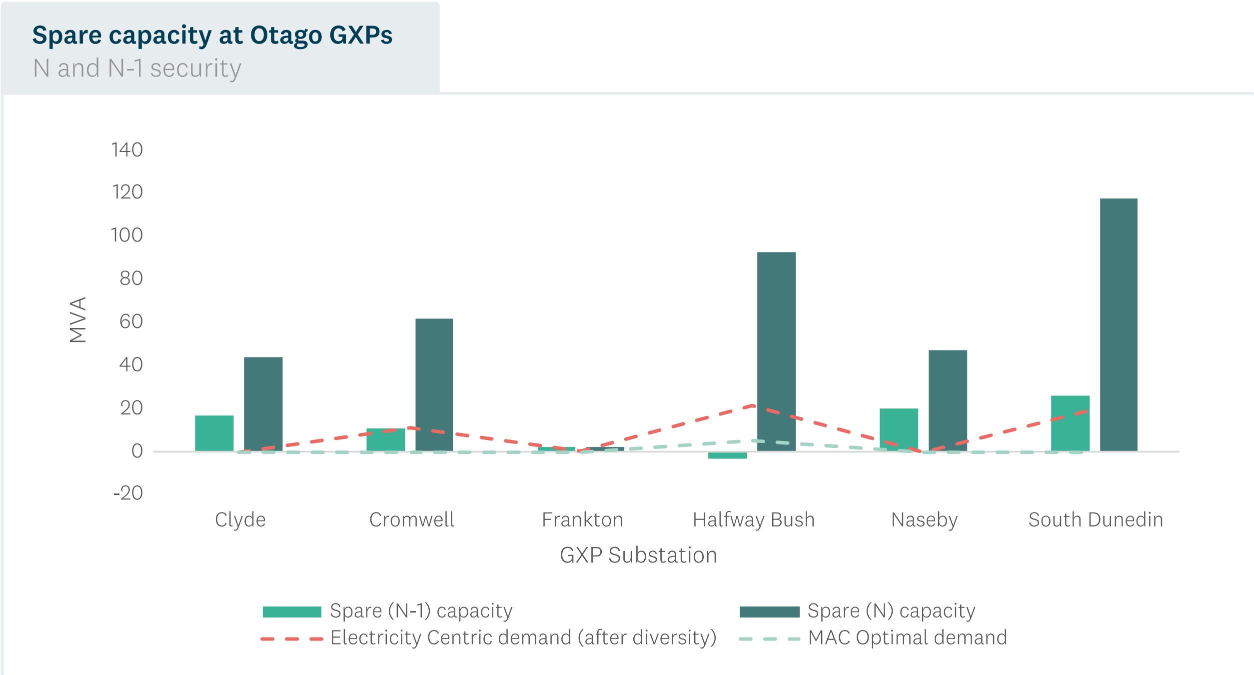
- The 'Electricity Centric' pathway, where all of the Otago RETA sites choose to electrify
- A 'MAC Optimal' pathway, where only those sites that have lower marginal abatement costs than biomass (see Section 7.1) electrify (blue dashed line).

Section 7.2 describes these scenarios more fully. Note that the dashed lines in Figure 58 assume that none of the sites actively manage their demand to avoid system peaks; again, this is a conservative view of peak demand.



Central Otago, New Zealand. Credit – Aurora Energy.

Figure 58 – Potential combined effect of site decisions at each GXP on spare capacity. Source: Ergo



On this analysis:

- In the Electricity Centric scenario, electrification at Halfway Bush and Cromwell would use up all spare N-1 capacity, and some amount of spare N capacity. However, Cromwell would only exceed N-1 for only very short periods of time, which would likely be tolerable.
- In the MAC Optimal scenario, electrification causes N-1 to be exceeded at Halfway Bush.

However, as outlined earlier, our spare capacity metric is based on the difference between N-1 (and N) capacity at the GXP and Transpower's conservative prudent demand forecast. This forecast is a '90th percentile' forecast – that is, a somewhat worst-case assessment of peak demand. To illustrate the conservatism in this forecast, Transpower's demand forecast for 2023 at Halfway Bush is 130MW whereas the observed peak in 2022 was 110MW (see Figure 55). Hence, in 2022, there is potentially 20MW more spare N-1 capacity today than Ergo's analysis in Figure 59 suggests).

The primary cause of this large discrepancy at Halfway Bush is the presence of embedded generation at Halfway Bush (discussed above). Transpower's demand forecast prudently removes the effect that embedded generation has on the net peak demand at the GXP – there are a potential scenarios where this generation isn't available at times of peak demand. This approach is consistent with the 90th percentile framework for a prudent demand forecast. Transpower's 2022 Transmission Planning Report notes that Transpower and their customers "expect the embedded generation at Halfway Bush 33 kV will be available and sufficient to provide security to the load for the forecast period".

However, process heat users contemplating electrification at Halfway Bush should engage early with Aurora and Transpower to ensure that this expectation regarding embedded generation still applies should a number of RETA sites electrify.

9.4.3 Zone substations

While the assessment of the two RETA pathways against spare GXP capacity suggested that process heat decarbonisation was unlikely to trigger transmission upgrades, some potential upgrades to distribution zone substations were identified. These were:

- **Cromwell 33kV zone substation (Aurora)** – RETA sites considering connecting to the Cromwell GXP are Fulton Hogan Cromwell Asphalt Plant, an EV charging station, Cromwell Pool and Cromwell College. The combined peak demand of these loads is 13.63 MW, while the zone substation only has 10MVA of N-1 capacity. If this did trigger investment by Aurora, this may amount to $1.5M for each transformer, and potentially – if a number of these sites connected – a $4M switchroom upgrade due to lack of physical space in the existing substation. That said, this analysis assumes that the EV charging station is operating at 3.8MW at peak times; a more cost-effective solution would be for the EV charger to be managed dynamically to avoid this outcome. For example, peak-time charging could be made more expensive for EV owners, or the rate of charging could be limited to lower than 3.8MW at peak times.
- **Ward St zone substation, Dunedin (Aurora)** – There are six RETA sites that could potentially connect to this zone substation, with peak load requirements of 11.27MW. The zone substation has 14MW of spare N-1 capacity, which is sufficient capacity. However, this number of new connections may cause a need for an expansion of the physical space in the substation at a potential cost of $4M.
- **North City zone substation, Dunedin (Aurora)** – Ergo explored two scenarios of RETA connections here. The highest combined peak demand (10MW) resulted from a scenario where Otago Polytechnic, Dunedin Energy Centre, and University of Otago and Burns House all connected. Again, while the zone substation has sufficient N-1 capacity for these sites, physical space in the zone substation may not permit the new connections. Upgrades to accommodate new connections could cost ~$4M.

Alexandra Substation, Otago, New Zealand. Credit – Aurora Energy.

9.5 The role of flexibility in managing costs

9.5.1 Why flexibility?

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

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

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

9.5.2 How to enable flexibility

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

- Each site operates in a way that suits its own production schedule.
- The investment in the network is required if the connection of the electrified process causes network security to fall below its current level (i.e. from N-1 to N).

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

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

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

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

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

ii. **Minimising retail costs** – Section 9.2.3 outlined how sites that choose to face a more stable retail tariff (rather than direct exposure to wholesale prices) will likely be provided with a set of 'shaped' prices that (at the very least) reflect time of year, weekdays vs other days, and day versus night (see Figure 31). Some pricing arrangements may have more granular prices (e.g. different prices for each 4-hour 'block' of the day). This provides incentives for site operators to schedule production in a more predictable way (compared with a volatile wholesale price), again lowering electricity procurement costs by scheduling production away from high priced periods.

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

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

v. **Reducing capital costs of connection** – Similarly, when considering the capital cost associated with accommodating newly electrified processes, Section 9.3 outlined that a key factor is the current spare capacity at peak times in the existing network. Flexibility in electricity consumption can potentially reduce the cost of network upgrades in two different ways:
   - Ensuring demand from the site is reliably[117] lower during the times of peak network demand (when spare capacity is at its lowest), thus reducing the amount of network investment required from the network company.
   - Allowing the site's demand to be reliably interrupted should a part of the network fail (known as a 'special protection scheme'). The network company may, based on a risk assessment, allow network security to drop from N-1 to N-0.5, or N at peak times (see Section 9.3.2), thus requiring a lower level of investment in network upgrades, on the understanding that should a component of the network fail , the site will immediately[118] reduce demand so that the network remains stable and thus doesn't affect other consumers connected to the network.

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

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

vi. **Other market services** – Finally, there are a number of 'ancillary services' that Transpower, as the electricity 'system operator' must procure which help it manage the whole system's stability and resilience. A reliably responsive demand site may be able to provide services into these markets, and earn revenue from them. Participation can be as little as 1-2 response events per year that require a load drop of only a number of minutes. We note that the industry is currently discussing how these services may evolve as the amount of intermittent wind and solar increases on the system, including new types of ancillary services that may arise[119].

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

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

9.5.3 Potential benefits of flexibility

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

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

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

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

[121] See Reeve, Stevenson, Comendant (2021), *Cost-benefit analysis of distributed energy resources in New Zealand*. Available here: https://www.ea.govt.nz/documents/1742/Sapere_CBA.pdf ; Orion (2023), 1 March 2023; Boston Consulting Group (2022), *The Future is Electric*.

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

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

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

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

9.5.4 Who should process heat users discuss flexibility with?

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

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

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

[122] See https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/consultation/price-discovery-under-100-renewable-electricity-supply/, specifically the Demand Side Flexibility case studies available at https://www.ea.govt.nz/documents/1254/DSF-case-studies-FINAL-1.pdf

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

Dunedin Energy Centre, Otago, New Zealand. Credit – Pioneer Energy.

10 Otago RETA insights and recommendations

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

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

The aim of this report, which is the culmination of the RETA planning stage for the Otago region, is to:

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

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

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

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

A 'whole-of-system' perspective would go further than this RETA to incorporate other sectors. The transport[124] sector will, in all likelihood, decarbonise through a combination of sustainable fuels (including bioenergy and electricity), and in some situations process heat and transport will compete for the same sources of fuel. The nature of the decarbonisation technologies that underpin these decisions is changing quickly, and a system-level view – even at a regional level – will allow decision makers and policy makers to be able make informed choices and identify challenges, gaps and opportunities. This makes a RETA more complex, but more insightful in identifying system challenges and solutions.

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

10.1 Biomass – insights and recommendations

The analysis above shows that comprehensive extraction and conversion of estimated processor and harvesting residues (after the deduction of the existing consumption of these residues) has the potential to supply the biomass demand arising under all pathways modelled.

Cutover residues may be more complex and more expensive to recover than modelled here, although we have used a pragmatic assessment based on expert opinion.

Our analysis suggests there are likely to be at least 36 process heat users seeking biomass as a fuel (including confirmed fuel switching projects). There needs to be a high degree of coordination between these organisations and forestry companies to ensure all parties – on the supply side and demand side – have the confidence to extract, process and consume residue-based biomass as a long-term option. There are a number of opportunities to increase this coordination and confidence, including:

- More analysis, pilots and collaboration with existing forestry organisations extracting residues (e.g. Port Blakely) should be undertaken to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering residues.
- In tandem, work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.
- 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.
- Mechanisms should be investigated and established to help give confidence over prices, volumes and contracts for example regular (e.g. annual) updates to the biomass analysis in this RETA, encouraging use of industry-standard long-term contracts for process heat service-level biomass supply[125] and greater transparency about (anonymised) prices and volumes being offered or traded.
- Analysis is also required to determine the impact of recovering these residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.
- Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.

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

10.2 Electricity – insights and recommendations

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

Process heat users will make the best decarbonisation decisions if they clearly understand the potential costs and how enabling flexibility in their consumption will help reduce those costs. Transpower and EDBs can only make the best decisions about upgrades if they have the best information about process heat organisations' intentions, and realistic levels of flexibility that process heat organisations can offer.

This RETA has sought to increase the level of information shared, but we acknowledge that the world is changing quickly and this needs to be a continued process. The more up-to-date information is, the better able organisations are to adapt to a changing world. Electricity industry participants need to find ways to increase the pace of information exchange.

As noted above, it appears unlikely that the conversion of RETA process heat to electricity will trigger significant transmission upgrades. However, there are some potential situations where EDBs will need to upgrade zone substations to accommodate some scenarios of fuel switching. It is critical that process heat users engage with EDBs early, and often, about their plans.

10.2.1 The role we need EDBs to play

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

- Stay abreast of process heat users' intentions regarding timing of, and capacity required for, electrification decisions. This will enable EDBs to accommodate their intentions in their network plans and demand forecasts, in order to make efficient use of network resources.
- Help Transpower and other stakeholders (as necessary) receive information from process heat users relevant to their planning at an early stage.
- Provide process heat users with timely advice and a good understanding of network investment, and network security levels, that can be incorporated into process heat business cases.

A related opportunity is for the network companies to provide a stronger coordinating function for each region's large electrification initiatives.

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

- **What their likely electricity consumption means for network upgrades.** The screening-level estimates provided in Section 9 provide a starting point, but more detailed discussions and engineering studies are required to firm these up. An important piece of information here is how the process heat user's demand (see below) aligns with existing demand patterns on the relevant parts of the network.
- **The risks and cost trade-offs of remaining on N security relative to N-1 (or N-0.X if available).** The EDB will have sufficient history of network outages to provide a realistic expectation of the frequency of network interruptions, as well as the duration of any interruption to supply.

- **Network charges and network loss factors relevant to their connection location.** As outlined in Section 9, we have estimated an average level of network charges across the two EDBs involved in this Otago RETA, but the network charges for any individual process heat customer will depend on their particular location.
- **A clear process, timeframes and information required for obtaining network connection[126].** These processes should have realistic timeframes and the nature of the information that each stage of the process will provide the process heat user, and the data and information network companies need from the process heat user at each stage (see below).
- **How flexibility in their electricity consumption and/or the level of network security they desire could impact the cost of connecting them to the network.** Like network charges and loss factors, the degree to which Transpower and EDBs can be flexible with network security and therefore the extent of network upgrades required depends on the connection location.
- **How upgrade projects could be accelerated, for example, through:**
  - Early and bulk procurement of critical long lead time equipment (items such as transformers, switchboards, cable, conductors etc).
  - Consideration of expedited delivery (often suppliers will expedite for a premium or offer air freight options).
  - Paralleling design and build activities where possible to reduce durations.
  - Using commercial levers in contracts to expedite (i.e. delivery incentives or similar).

10.2.3 Information process heat organisations need to seek from electricity retailers

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

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

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

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

- The nature of their electricity demand over time (baseload and varying components), especially what time of day and time of year their demand is likely to reach its maximum level.
- The flexibility in their heat requirements, which may allow them to shift/reduce demand, potentially at short notice, in response to system or market conditions.
- The level of security they need as part of their manufacturing process, including their tolerance for interruption.
- Any spare capacity the process heat user has onsite.

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

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

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

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

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

For process heat users to be able to assess the benefits of process flexibility, they will need an improved level of information from electricity industry participants. EECA recommends better and more transparent information be published by EDBs, retailers, and the Flex Forum about the benefits to process heat users from enabling flexibility in consumption, and the types of commercial arrangements (between electricity consumers and retailers/EDBs) that should exist to provide these benefits[127].

10.3 Pathways – insights and recommendations

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

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

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

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

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

10.4 Summary of recommendations

In summary, our recommendations are:

- **More analysis, and potentially pilots, should be conducted to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering harvesting residues.**
- **Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.**
- **Analysis is required to determine the impact of recovering harvesting residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.**
- **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.**
- **Mechanisms should be investigated and established to help suppliers and consumers to see biomass prices and volumes being traded, and have confidence in being able to transact at those prices for the volumes they require. These mechanisms could include standardised contracts which allow longer-term prices to be discovered, and risks to be managed more effectively.**
- **National guidance or standards should be developed, based on international experience tailored to the New Zealand context regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.**
- **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**
- **EDBs should develop and publish clear processes for how they will handle connection requests in a timely fashion, opportunities for electrified process heat users to contract for lower security, and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).**
- **EDBs and process heat users should 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.**
- **To support this early engagement, EDBs should explore, in consultation with process heat users and EECA, 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 ensure Transpower and other stakeholders (as necessary) are aware of information relevant to their planning at an early stage.**

- **Retailers, EDBs and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.**
- **EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.**
- **EECA should expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**
- **Ministries (such as Ministry for the Environment) to work with reputable organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.**
- **Process heat users should enquire about government co-funding where the economics of decarbonisation are challenging; where they are economic, EECA encourages organisations to explore the potential for self-funded acceleration.**

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

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

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

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

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

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

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

11.1.1 Connection charges

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

Where there are multiple customers on one connection then connection charges are allocated to customers on the basis of their anytime maximum demand (AMD) to the total of all customer's AMDs. This is a way in which the EDB could allocate connection charges to their customers that is consistent with the TPM. We can't know what the total of all AMDs within the EDB's network is (behind the GXP) and so we will simply assume that the AMD of the combined network is the total of all AMD.[128] This gives a worse case allocation for the process heat user. AMD is the average of the twelve highest half-hour peaks in the given year or other time period. We have assessed the AMD for the process heat user based on data provided to us, which gives 18.1 MW. We assume that the process heat user peak demand will remain constant unless they physically invest in new plant. For the GXP demand we use the peak demand forecast from Transpower's Transmission Planning Report 2021.

This gives a forecast of connection charges for the process heat user's current demand in Table 17.

Table 17 – Forecast CC for the process heat user current demand

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

To assess the increase in charges for the addition of the electrode boiler we add 24MW to the process heat user's current AMD and to the EDB AMD but make no other alterations. Again, this is the worst case for the process heat user and gives the connection charges forecast in Table 18.

Table 18 – Forecast CC for the process heat user demand and new boiler

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

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

11.1.2 Benefit-based charges

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

The investments and allocations that apply for the GXP are given in Table 19.

Table 19 – BBI projects and allocations for the GXP

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

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

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

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

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

There is a further complication, though. Different IRA calculations apply according to the nature of the investments. We think it unlikely that a distributor's methodology would be considered inconsistent with the TPM by simply picking one of the methods to apply to the total BBC. Both methods use the same calculation period being three years of data lagged by two years, i.e. n[128]-4 to n-2 inclusive, in this case 2018 to 2021. The allocation would then be based either on peak coincident demand over that period or total consumption over that period. the process heat user has a very low-capacity factor for an industrial user at 32%. This means that the two approaches yield very different allocations. Using peak coincident demand (using our assumptions from above) would give 16.5% and using consumption would give 3.6%. Given the peaking requirements for the process heat user and that most of the TPM Appendix A BBIs could be described as investments to meet peak demand, we think that the EDB might use 16.5%. This would give the process heat user a starting BBC allocation of $175k (i.e. prior to the 25MW increase from the new electrode boiler).

As TPM Appendix A BBIs are fixed allocations then the EDB is likely to treat the starting allocation for the process heat user as a fixed allocation. This gives the outcome in Table 20.

Table 20 – Worst case BBC allocation to the process heat user

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

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

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

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

[128] Here, n refers to the current year.

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

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

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

As the increase in the EDB's charges is attributable to the process heat user if the electrode boiler goes ahead then the resulting charges are shown in Table 21.

Table 21 – BBC for the process heat user with electrode boiler

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

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

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

11.1.3 Residual charge

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

The AMD that is applied for $AMDR_{baseline}$[129] is different to the one that applies for CC. However, we will assume the same allocation factor for AMD applies for the $AMDR_{baseline}$, i.e. that the process heat user will get 16.5% of the RC. If we assume there is no significant difference in total EDB consumption, then there will be no significant difference in the allocation of RC to the process heat user. In practice, this will depend on many factors including changes in consumption within the GXP network and elsewhere. This gives RC for the process heat user as shown in Table 22.

Table 22 – RC for the process heat user without boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M

If the boiler is added there will be no immediate impact on the EDB's RC due to the adjustment factor being based on lagged consumption. After four years then consumption is based on four years of average consumption lagged by four years. Assuming that the new electrode boiler adds 138 GWh per year starting in the 2023/2024 pricing year, then the adjustment in charges is shown in Table 23.

Table 23 – RC for the process heat user with boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Adjustment factor	1.00	1.00	1.00	1.00	1.00	1.08	1.16	1.24	1.32
EDB charges	$4.60M	$4.60M	$4.60M	$4.60M	$4.60M	$4.97M	$5.35M	$5.72M	$6.09M
Increase for boiler	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.37M	$0.75M	$1.12M	$1.49M
Process heat user with boiler	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.50M	$1.88M	$2.25M

The charges reach their fully adjusted value in 2031.

[129] Anytime Maximum Demand for Residual Charges baseline.

11.1.4 Summary of charges

Table 24 summarises the outputs of Table 17, Table 20, and Table 22 to give the forecast allocation of transmission charges to the process heat user without the proposed electrode boiler.

Table 24 – Forecast allocation of transmission charges to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
CC	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M
BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M
Total	**$1.02M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.00M**

Table 25 summarises the outputs of Table 18, Table 21, and Table 23 to give the forecast allocation of transmission charges to the process heat user with the proposed electrode boiler.

Table 25 – Forecast allocation of charges to the process heat user with boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
CC	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M
BBC	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M
RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.5M	$1.88M	$2.25M
Total	**$1.40M**	**$1.40M**	**$1.40M**	**$1.40M**	**$1.39M**	**$1.76M**	**$2.13M**	**$2.51M**	**$2.88M**
Increase	**$0.39M**	**$0.40M**	**$0.40M**	**$0.40M**	**$0.39M**	**$0.76M**	**$1.13M**	**$1.51M**	**$1.89M**

Table 25 also shows the increase in transmission charges after the boiler is installed. The charges are fully increased by 2031 to $2.88M, a $1.89M increase from what would happen without the boiler (ceteris paribus). Calculating the present value of 10 years (at 8% discount rate) of increased transmission charges gives $5.53M

Clyde Dam, Otago, New Zealand. Credit – Rachel Mataira.

12 Appendix B: TIMES modelling of Otago's fuel switching decisions

12.1 Introduction

To model a cost-efficient pathway to decarbonisation, TIMES-Otago was created. This is based upon the IEA ETSAP TCP TIMES energy model generator, a bottom-up modelling system used worldwide. TIMES uses a linear programming solver to minimise the total energy system cost over the entire modelled horizon (2018 – 2049).

The TIMES-Otago model is a stand-alone model separate to EECA's TIMES-NZ model, which consists solely of process heat assets in the Otago region and is based upon RETA data.

In basic terms, the model finds the cheapest way to meet the projected heat demand of each site over the modelled horizon, essentially by considering the trade-off between continuing to run existing fossil fuelled assets and paying rising NZ ETS prices, compared to the cost of undertaking fuel switching to a low carbon heat source (biomass or electricity). The key output from the model is that it tells us the most optimal fuel choice for each site, and in what year it becomes economic for the site to undertake fuel switching.

Clutha River, Otago, New Zealand. Credit – Rachel Mataira.

12.2 Model inputs

12.2.1 Current state

Existing installed boiler capacity and fuel consumption by site is obtained from the demand assessment workstream. We apply an estimated boiler efficiency to fuel consumption values to obtain site process heat demand. This then forms the basis of a projection of process heat demand by site for the entire model period.

12.2.2 Fossil fuel prices

We take price forecasts for fossil fuels – coal, diesel, and LPG – from RETA analysis.

12.2.3 Carbon price

The price applied to CO_2 emissions is the primary driver of decarbonisation in the model. We use a modified version of the CCC's demonstration pathway, which accounts for the difference between the CCC's pathway and the actual carbon price over the past year or so.

12.2.4 Demand reduction, heat pump, and fuel switching projects

Confirmed demand reduction, heat pump, and fuel switching projects have been implemented as scheduled.

Unconfirmed demand reduction and heat pump projects are implemented in 2023 and 2024 respectively. This reflects the fact that these projects are generally economically favourable and hence sites will implement them ASAP. We assume that unconfirmed fuel switching projects will not take place until any DR and HP projects are complete, hence 2025 is the earliest that sites can undertake a fuel switching project.

The capital costs for fuel switching projects are provided by the demand assessment workstream (which uses ETA data where known, and default values based on required capacity where unknown).

For electrification projects, if an electrical supply upgrade is required, the project capital cost includes the portion of the upgrade cost that the site must pay.

We also apply annual network charges (on a per MW basis) to electrification projects. With the exception of this network charge, operation and maintenance costs are not included for either biomass or electrification projects as these are minor compared to fuel and NZ ETS costs.

The model uses a discount rate of 6%.

12.2.5 Additional constraints and special cases

All sites which use coal must transition by 2037 at the latest to align with the Government's intention that coal for low and medium temperature process heat be phased out by that year.

Facilities covered by the carbon neutral government programme, such as public schools and hospitals, must transition to a low carbon heat source by 2025.

12.2.6 Low carbon energy sources

12.2.6.1 Electricity

There is no constraint on the availability of electricity in the model – it is assumed that there is sufficient supply to meet demand (or that supply upgrades can meet demand) if a site is willing to pay for it.

We apply a special flat rate for the first 10 years from when fuel switching projects become available (i.e. from 2025 to 2034 inclusive). This reflects special offers from retailers to encourage process heat electrification. From 2035 onwards, we use EnergyLink's monthly electricity price forecast.

Site-specific load curves are applied where known, otherwise default load curves based on sector are used. This allows the model to factor in the seasonality of electricity prices as well as seasonal variability in site demand.

12.2.6.2 Biomass

We use data from the biomass availability and cost workstreams to generate biomass price and supply inputs for the model. Biomass supply is split into tranches of differing quantities and prices, based on the upstream source of the biomass. As the model increases its use of biomass, it will exhaust the cheaper tranches of supply and thus need to start using more expensive inputs. This allows for greater granularity than providing a simple average cost based upon expected demand.

12.3 Results

By aggregating the model's fuel choice and transition year for each site, we obtain a suggested optimal pathway for the region to follow. This pathway can be seen in the graphs below, and suggests decarbonisation is economically attractive for Otago sites based on the assumptions used.

Further explanation is as follows:

Where heat pumps are an option for outright fuel switching (i.e., in sites which only require low temperature heat as opposed to steam), these are preferred thanks to their high thermal efficiency.

For sites with coal, ALL sites undertake fuel switching prior to the 2037 deadline.

Factors determining year of fuel switching and fuel choice include:

- **Boiler utilisation** – The lower the utilisation rate of the boiler, the less likely it will be economic to fuel switch (running cost savings are relatively less significant compared to the upfront CAPEX required).
- **Project capital costs** – There are numerous factors which could influence this, for instance, some sites might have an existing coal boiler and fuel handling system that can be relatively easily converted to run on biomass, and this may be significantly cheaper on a per MW basis compared to other sites which would need a brand-new boiler and fuel handling system. Another factor influencing CAPEX is the level of complexity/cost of any electrical supply upgrades required for electrification projects.
- **Ongoing running costs**
- **Boiler efficiency** – Default of 80% for biomass boilers and 99% for electrode boilers (vs 85% for diesel and 78% for coal)
- **Annual per MW transmission/distribution costs**

Figure 59 – Emissions reduction timeline from TIMES model. Source: EECA

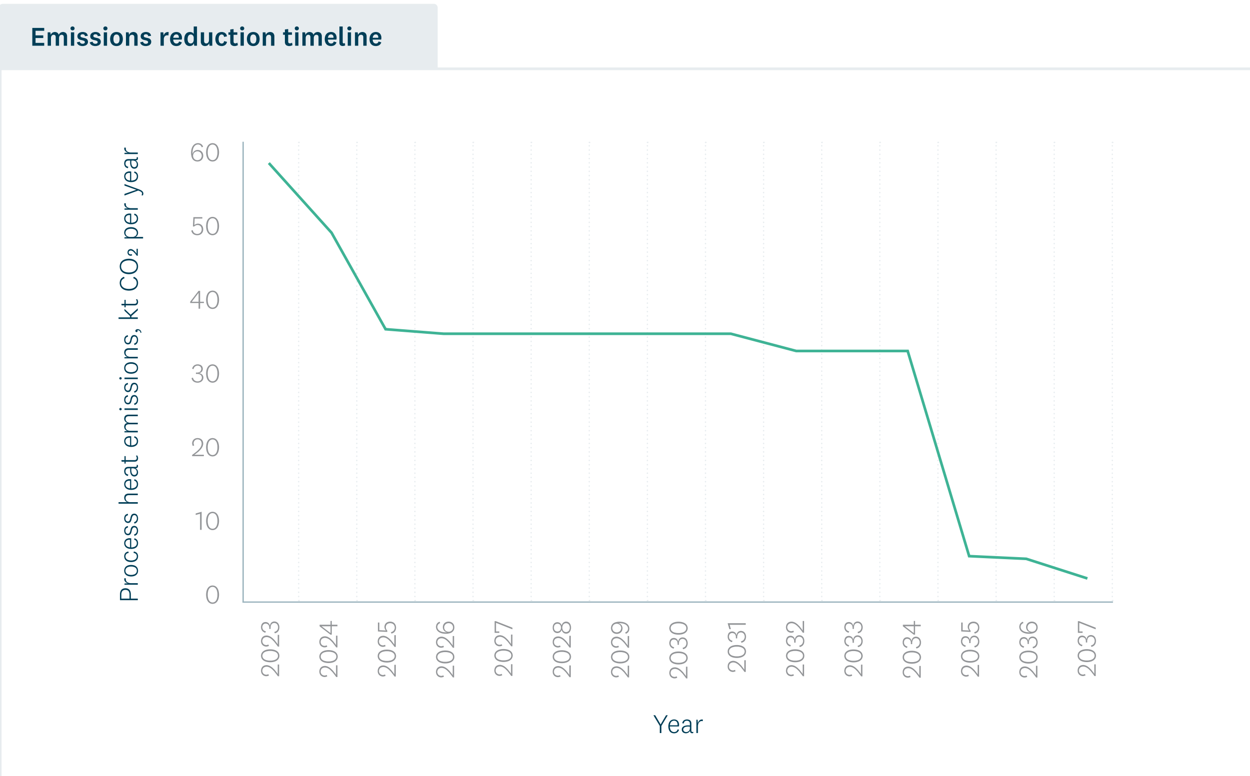
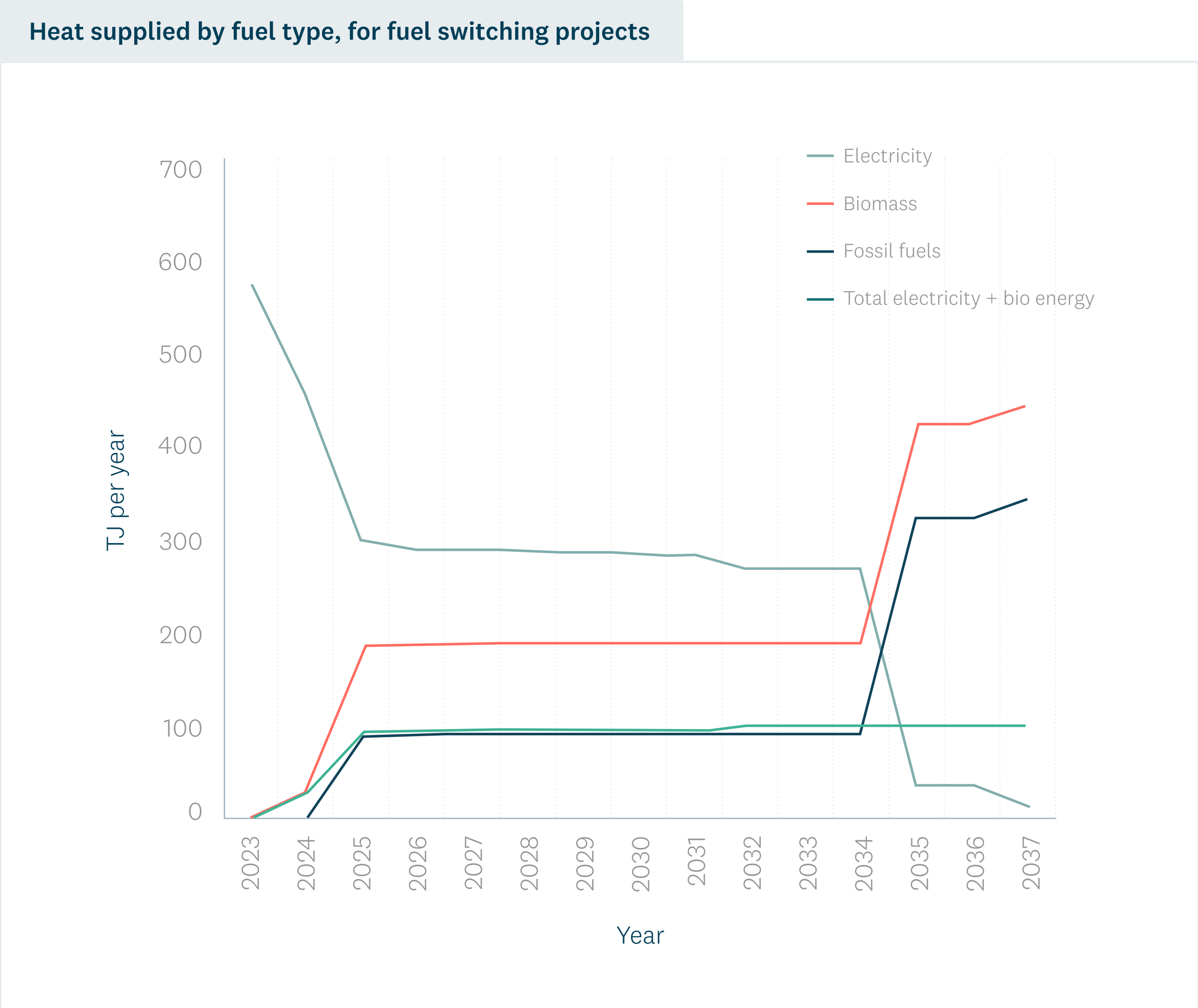


Figure 60 – Heat supplied by fuel type (or fuel category).



Mechanical Vapour Recompression System, Auckland, New Zealand. Credit – BlackonBlack Events.

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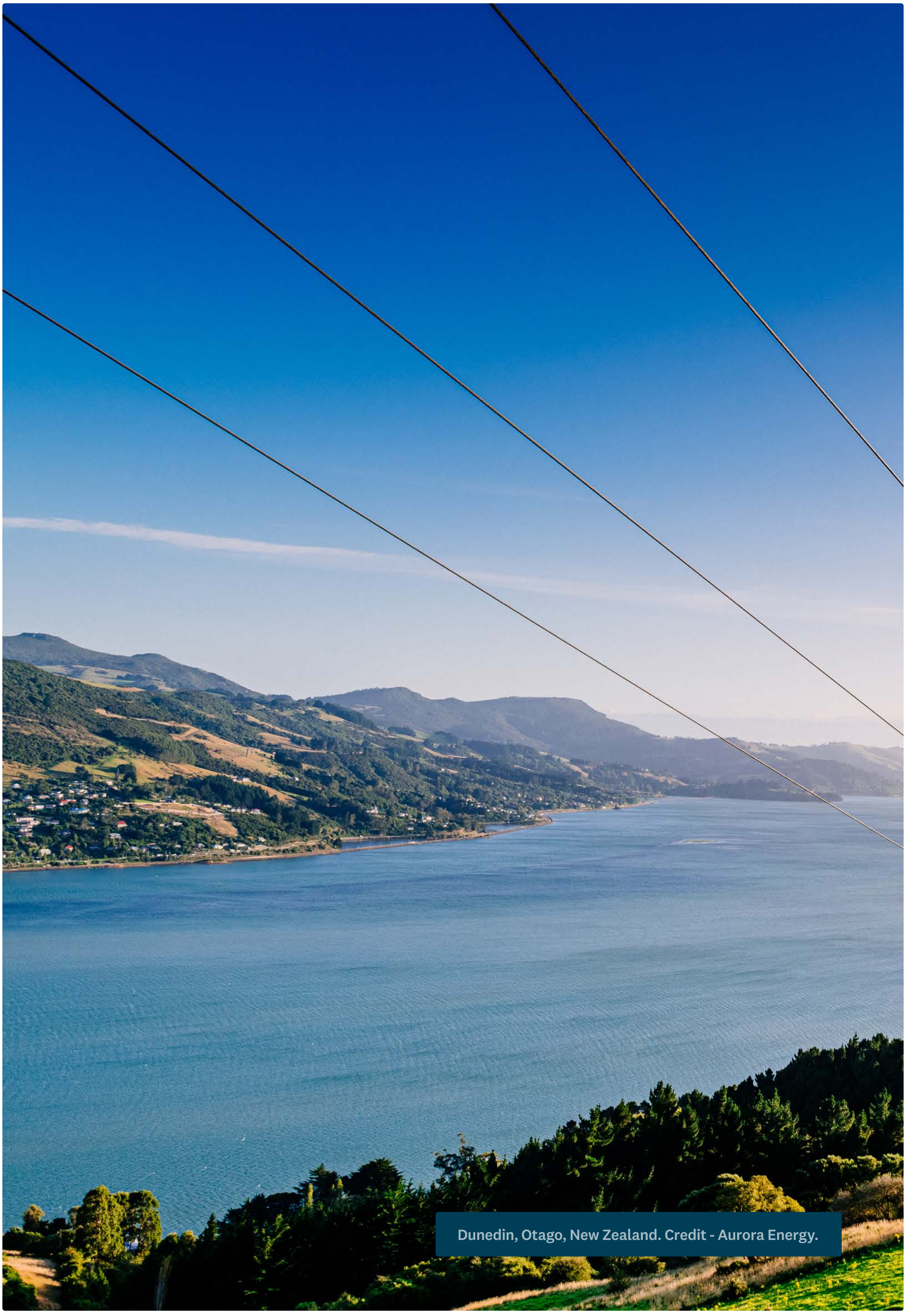
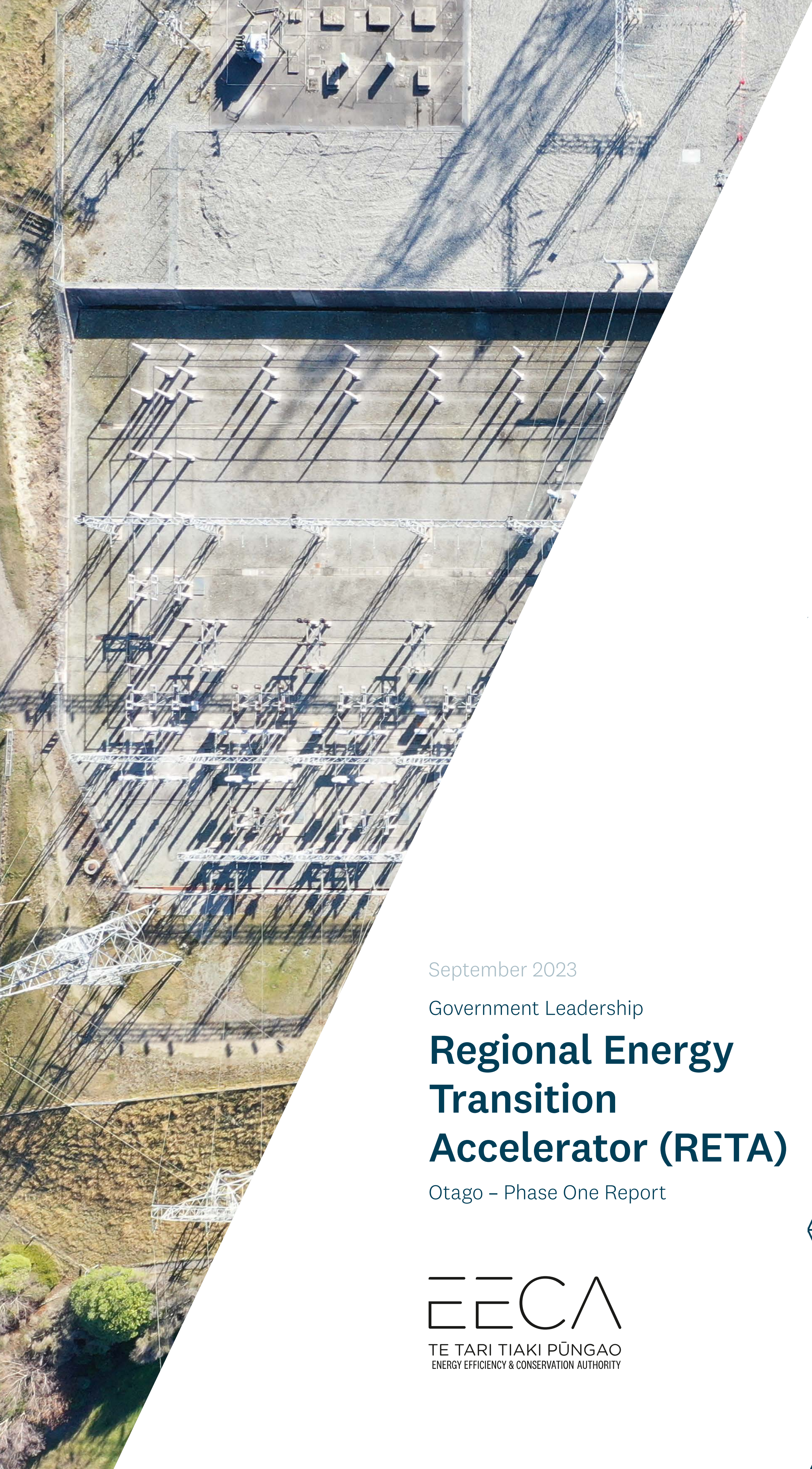


Dunedin, Otago, New Zealand. Credit - Aurora Energy.



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Government Leadership

Regional Energy Transition Accelerator (RETA)

Otago – Phase One Report

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