Government Leadership

Regional Energy Transition Accelerator (RETA)

Taranaki – Summary Report

October 2024

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

He kupu takamua

E tutuki ai te whāomoomo ā-pūngao me te whakawhiti kora kaitā, me whai pārongo whai mana i te taha o te mahi ngātahi pakari ā-rohe. Kua hoahoatia te Taranaki Regional Energy Transition Accelerator (RETA) ki te poipoi i te māramatanga whānui ki ngā tūāoma e waiwai ana ki te whakaheke i te tukuwaro i te rohe mā tētahi hātepe mātau, ruruku pai.

Kei te iho o tēnei hōtaka ko te tohu i ngā arawātea me ngā taupā e motuhake ana ki a Taranaki i a mātou e whakaahua ana i ngā mahere rori whakawhiti pūngao ā-rohe. Ko Taranaki te rohe kotahi i Aotearoa e hua ake nei te haurehu (waiwaro rānei), ka mutu, he wāhi hirahira tōna i te tauritetanga ā-pūngao o Aotearoa. Ko te pae tawhiti, ka tutuki ngā herenga pōkākā o te wā i te rohe i te kapuni kora anake.

E motuhake ana ki a Aotearoa, ko ngā wāhi e rua i Taranaki e whakamahi ana hoki i te kapuni hei matū taketake. Ahakoa e āta aro ana tēnei pūrongo ki te whakamahinga o te pūngao hei hātepe pōkākā, e mōhio ana mātou ka whīwhiwhi ake te hātepe whakatau mō ngā rōpū whakahaere e whakamahi ana hoki i te kapuni i roto i ā rātou hātepe whakaputa.

E whakamahi ana tā mātou tātaritanga mō te rohe o Taranaki i a 2022 hei paepito mō te popono pūngao. Nō taua wā, kua whakaawe ngā kōpiritanga tuku haurehu i ngā utu kapuni, me te aha, kua panoni i ngā tauira whakapeto – e tino pērā ana i ngā taupuni e whakamahi ana i te kapuni hei matū taketake.

E whakaatu ana tēnei pūrongo i ngā ara whakaheke waro pōkākā huhua, e whakatauira ana i tā ngā whakatau tōpū a ngā kaiwhakamahi huhua ārahi i ngā rautaki mahi tahi ki ngā wero tūāhanga nō te tirohanga tukunga. Ka whakaatu i ngā angamahi whakatau hei whakaaro ake pea mā ngā rōpū whakahaere hātepe pōkākā i a rātou ka kōwhiri i ngā kora, i muramura mai ai ngā hua huhua ka taea.

E whakatauira ana hoki te pūrongo ka huri pea ngā whakatau i raro i ngā horopaki ā-utu maha. Mā te tirohanga ā-rohe e taea ai tētahi arotakenga whānui o ēnei tūāhuatanga, e mātau ake ai ngā whakatau a ngā kiritaki hātepe pōkākā, tuku kora anō hoki.

E tohu ana tēnei pūrongo i te tihi o te tūāoma whakamahere o te hōtaka, e tuku ana i ngā matapae me ngā mahere o te popono pūngao wera o te rohe, i te taha o ngā aromatawai tuku ngao whakahou.

E whanake ana te hōtaka RETA i ngā whāomoomo ā-pūngao, whakawhiti kora anō hoki kua whakaterea kētia i te rohe. He huhua ngā pakihi i te Tairāwhiti kua whai kē i tētahi ara puhanga-iti, ā, kua whakamaheretia ki EECA.

I hua ake ngā mōhiotanga i runga i te āta mahi tahi ki a Trust Tairāwhiti – the Regional Economic Development agency, local EDB Firstlight Networks, Transpower, ngā kamupene ngahere o te rohe, ngā pūtukatuka rākau, ngā kaiwaihanga hiko me ngā kaihoko, otirā ngā kaiwhakamahi pūngao ahumahi waenga, ki te nui. E mihi nui ana ki ngā rōpū whakahaere nei i tā rātou whai wāhi mai, ā, i tō rātou hiamo anō hoki. E hiamo ana mātou ki te tautoko tonu i te rohe i a tātou ka mahi tahi ki te tūhura i tōna pitomata.

1 Foreword

Achieving energy efficiency and fuel switching at scale requires valuable information alongside strong regional collaboration. The Taranaki Regional Energy Transition Accelerator (RETA) has been designed to foster a comprehensive understanding of the steps necessary for lowering emissions in the region through a well-informed and coordinated approach.

Central to this programme is identifying unique, Taranaki-specific opportunities and barriers when crafting regional energy transition roadmaps. Taranaki is New Zealand's sole gas producing region and plays an important role in the supply of New Zealand's energy balance. The downstream opportunity is that current process heat requirements in the region are met almost exclusively by natural fossil gas.

Uniquely in New Zealand, two sites in Taranaki also use natural gas as a feedstock. While this report focuses specifically on energy use for process heat, we acknowledge that the decision-making process becomes more complex for organisations that also use natural gas in their production processes.

Our analysis for the Taranaki region uses 2022 as the baseline for energy demand. Since then, constraints in gas supply have influenced natural gas prices and, consequently, altered consumption patterns—particularly in facilities using natural gas as a feedstock.

This report illustrates various process heat decarbonisation pathways, demonstrating how the collective decisions of multiple users can lead to shared approaches to infrastructure challenges from a supply perspective. It presents diverse decision-making frameworks that process heat organisations might consider when choosing alternative fuels, highlighting the potential range of outcomes.

The report also demonstrates how decisions may change under various different pricing scenarios. A regional view enables a comprehensive evaluation of these factors, allowing process heat consumers and fuel suppliers to make more informed decisions.

This report marks the culmination of the programme's planning phase, offering forecasts and maps of regional stationary heat energy demand, alongside renewable energy supply assessments.

The RETA programme builds on energy efficiency and fuel switching work already happening in the region. Several businesses in Taranaki already have a low-emissions pathway mapped out with EECA.

Surfacing the insights has involved working closely with Venture Taranaki – the Regional Economic Development agency, local EDB Powerco, Transpower, regional forestry companies, wood processors, electricity generators and retailers, and medium to large industrial energy users. A big thank you to these organisations for their input and enthusiasm. We look forward to continuing to support the region as we work together to unlock its potential.

Dr Marcos Pelenur
Chief Executive, EECA

2 Acknowledgements

This RETA project 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 the Taranaki region
- Venture Taranaki
- Local Electricity Distribution Business Powerco
- 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:

- **Worley** – process heat demand-side assessment
- **Forme** – biomass availability analysis
- **Ergo Consultants** – electricity network analysis
- **EnergyLink** – electricity price forecast
- **Sapere Research Group** – report collation, publication, and modelling assistance

Mountain to Sea coastline New Plymouth. Photo credit: Venture Taranaki

> *The downstream opportunity is that current process heat requirements in the region are met almost exclusively by natural fossil gas.*
>
> **Dr Marcos Pelenur, Chief Executive, EECA**

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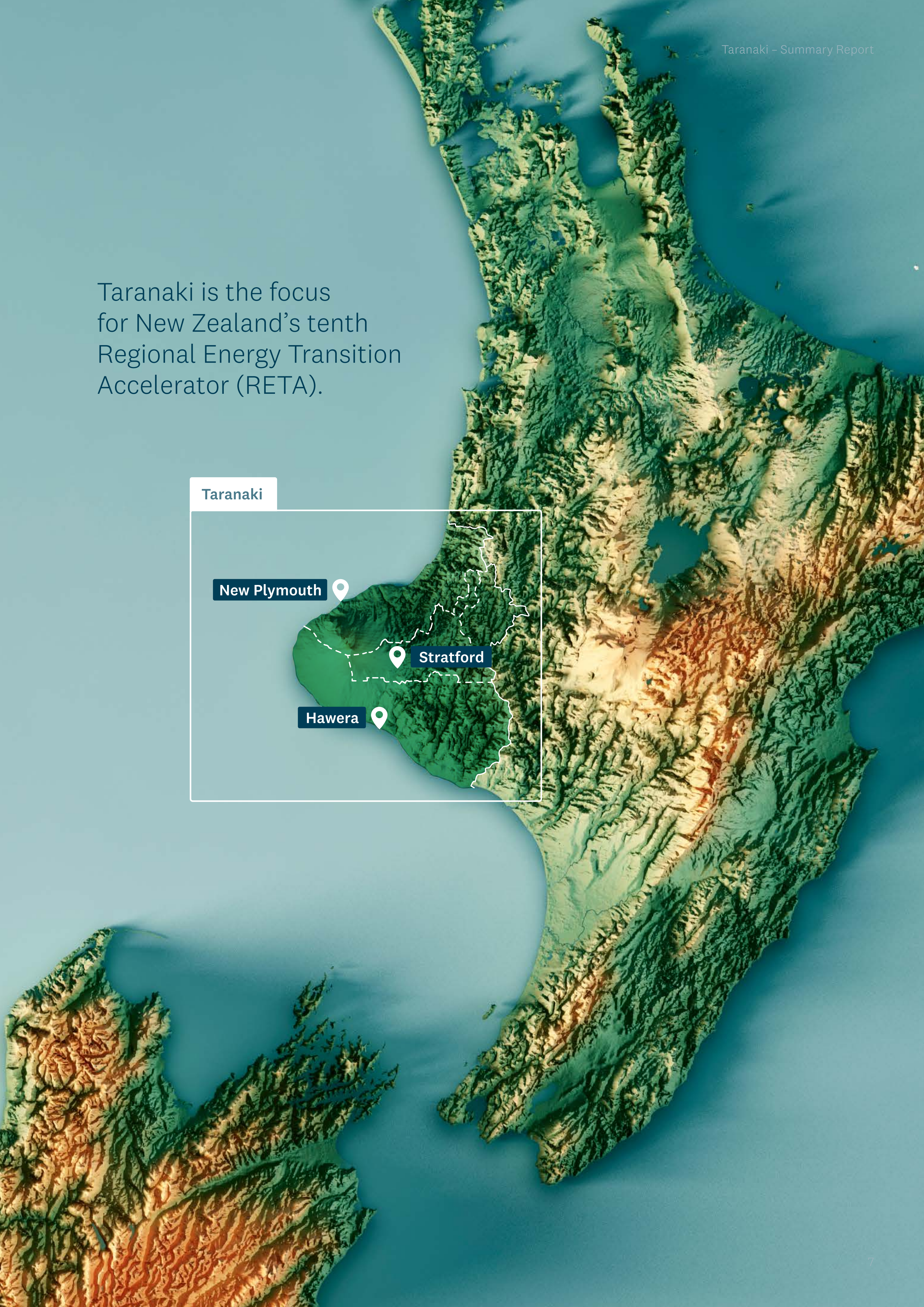
Taranaki is the focus for New Zealand's tenth Regional Energy Transition Accelerator (RETA).



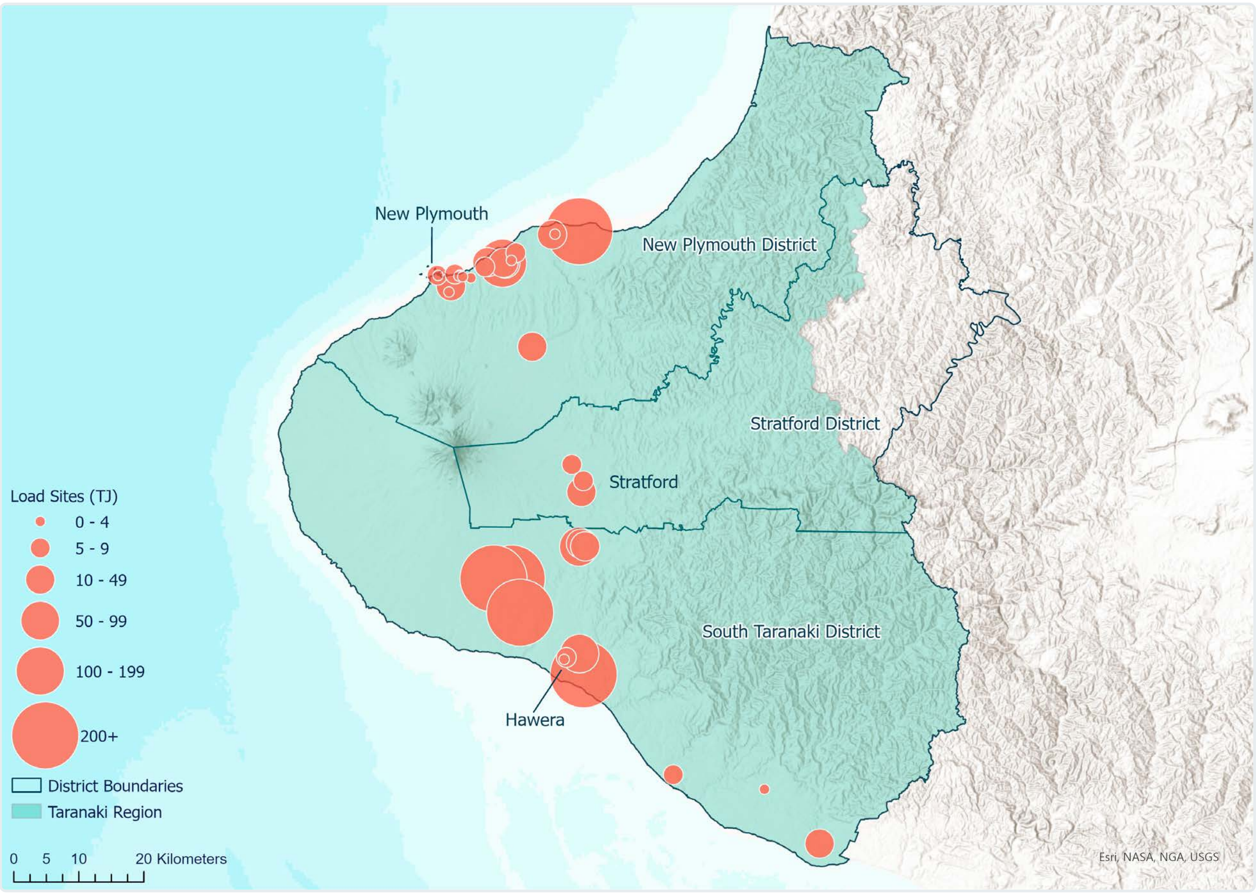
4 Taranaki overview

This report provides a snapshot of the planning phase of the Regional Energy Transition Accelerator (RETA) prepared for the Taranaki region (shown in Figure 1).

The report brings together information on the demand for fossil fuels for process heat in Taranaki, along with information on electricity network and biomass availability in the region, in order to:

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

Figure 1 – Map of area covered by the Taranaki RETA



The next phase of the RETA programme focuses on implementing recommendations from phase 1 to remove barriers or accelerate opportunities for decarbonisation of process heat.

Our analysis of energy requirements in Taranaki uses year 2022 as baseline. We note that since then, constraints in gas supply have affected prices for natural gas, and as a result have altered natural gas consumption patterns.[1] Uniquely in New Zealand two sites in Taranaki use natural gas as a feedstock as well as for process heat. Our analysis focuses on the use of fossil fuels for process heat energy only, and we recognise the decisions are more complicated for organisations that also use natural gas as feedstock.

There are 36 sites covered in the report, spanning the dairy, meat, industrial and commercial sectors.[2] These sites have fossil-fuelled process heat equipment larger than 500kW (i.e. process heat equipment details have been captured in the Regional Heat Demand Database) or sites for which EECA has detailed information about their potential decarbonisation pathway.[3] The sites, shown in Figure 1 by location and size of their annual energy requirements, collectively consumed 23,950TJ of process heat energy, almost exclusively in the form of natural gas, and produced 1,287kt pa of carbon dioxide equivalent (CO_2e) emissions.

Table 1 – Summary of Taranaki RETA sites fossil fuel process heat demands and emissions (2022)

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand today (TJ/yr)	Process heat annual emissions ($ktCO_2e/yr$)
Industrial	24	1,273	6,636	23,880	1,283
Commercial	12	13	20	70	4
Total	**36**	**1,286**	**6,656**	**23,950**	**1,287**

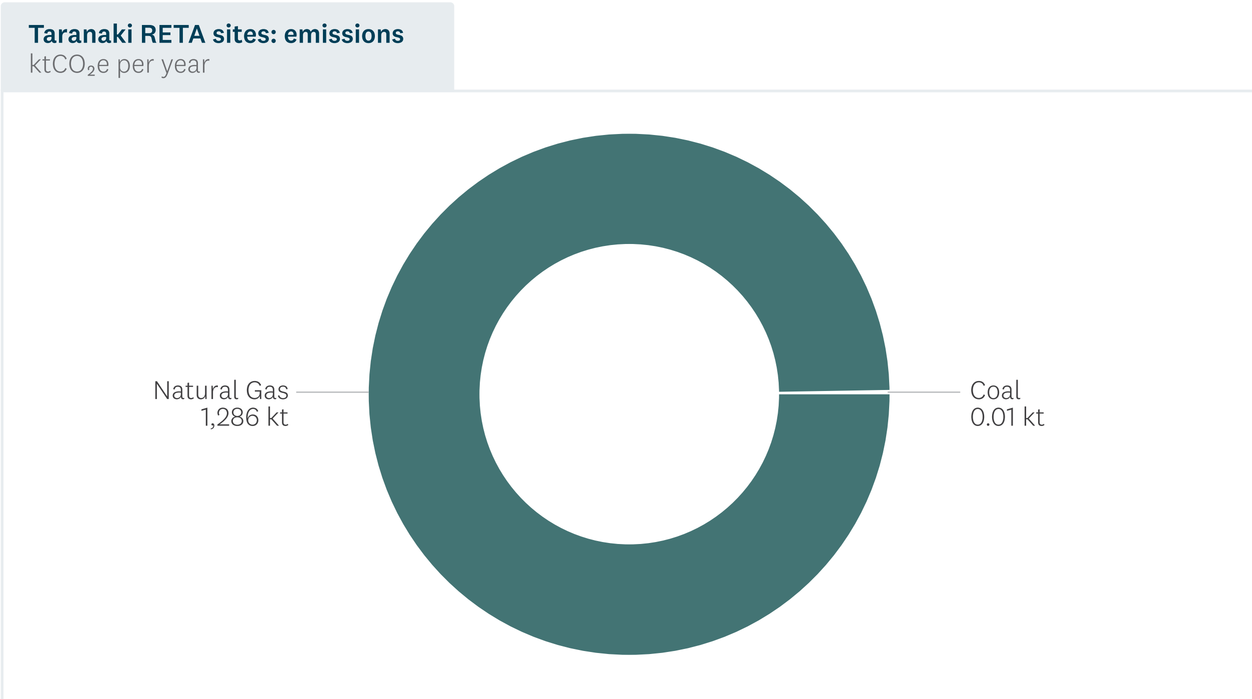
1 MBIE notes that gas production forecast is expected to fall below demand https://www.mbie.govt.nz/about/news/gas-production-forecast-to-fall-below-demand.

2 The commercial sector includes schools, hospitals, and accommodation facilities.

3 For many large process heat users in New Zealand, process heat decarbonisation opportunities have been captured in an EECA Energy Transition Accelerator (ETA) report.

Most Taranaki RETA emissions come from piped natural gas (Figure 2).

Figure 2 – 2022 annual emissions by process heat fuel in Taranaki RETA. Source: EECA



The objective of the Taranaki RETA is to demonstrate pathways that 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).
- Heat pumps (for heat requirements <100°C, which may be integrated with heat recovery) .
- Fuel switching (from fossil-based fuels to a low-emissions source such as biomass and/or electricity).

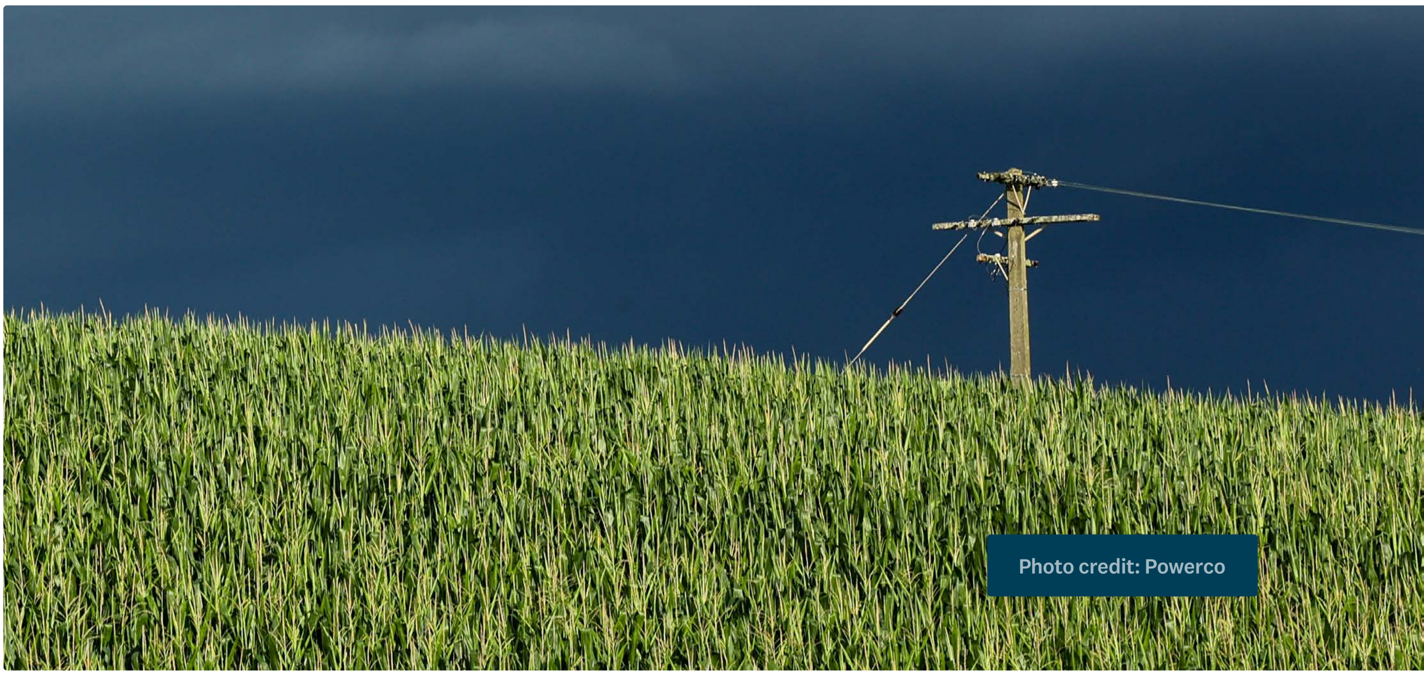
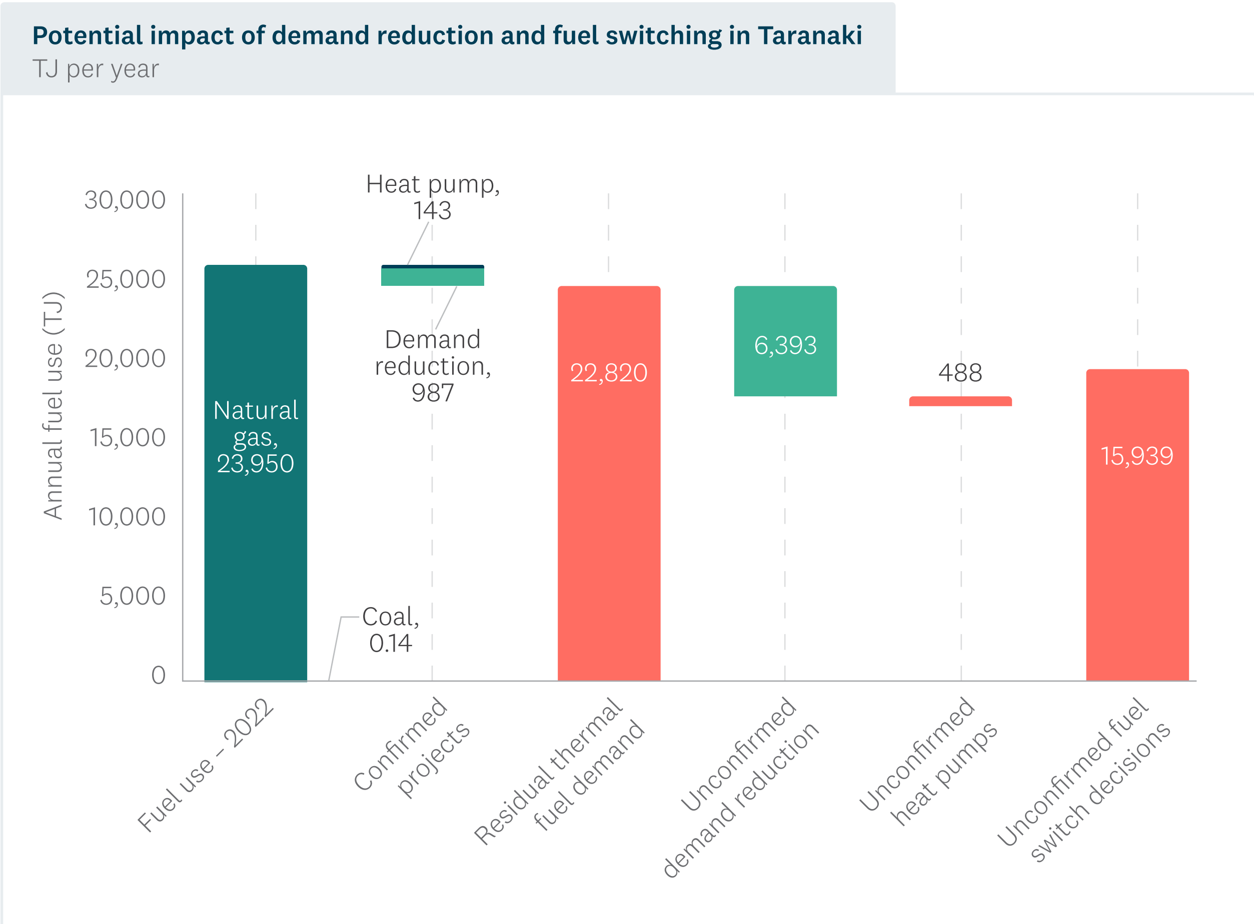


Figure 3 illustrates the potential impact on Taranaki's regional fossil fuel demand of process heat demand reduction and fuel switching decisions for those investments that are already confirmed and those where decisions are yet to be made.

Figure 3 – Potential impact of fuel switching on fossil fuel usage, 2022-2050. Source: EECA



Based on our analysis, 15,939TJ of the residual thermal demand could be considered for fuel switching (referred to as unconfirmed fuel switch decisions). The RETA analysis looks at the pathways by which these fuel switches could occur, considering both biomass and electricity as potential fuel sources. EECA's assessment focuses on the key issues that are common to all RETA process heat sites contemplating fuel switching decisions. This includes the availability and cost of the resources that underpin each fuel option, as well as the capacity of the networks to deliver the fuel to the process heat users' sites. This assessment is unique to the Taranaki region and has been used to simulate possible fuel switching pathways under different sets of assumptions. This provides valuable information to individual process heat decision makers, infrastructure providers, resource owners, funders, and policy makers.

4.1 RETA site summary

Across the 36 sites considered in this study, 92 individual projects have been identified across demand reduction, heat pumps and fuel switching.

Table 2 shows the current status of these process heat projects. Six have been confirmed by the process heat organisation (i.e. the organisation has committed to the investment and funding is allocated). The other 86 projects are unconfirmed (i.e. the process heat organisation is yet to commit to the final investment).

Table 2 – Number of projects in Taranaki RETA: Confirmed vs Unconfirmed. Source: Worley, EECA.

Status	Demand reduction	Heat recovery	Fuel switching	Total
Confirmed	2	1	3	6
Unconfirmed	33	11	42	86
Total	**35**	**12**	**45**	**92**

Demand reduction and thermal efficiency are key parts of the RETA approach 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, due to the higher capital and fuel intensity of this decision.

Table 3 shows the expected fuel demands remaining at each site after any demand reduction projects and/or heat pump projects are accounted for. The table presents biomass demands both in TJs and green tonnes (55% moisture content) and reports the peak demand from the boiler, should it convert to electricity.

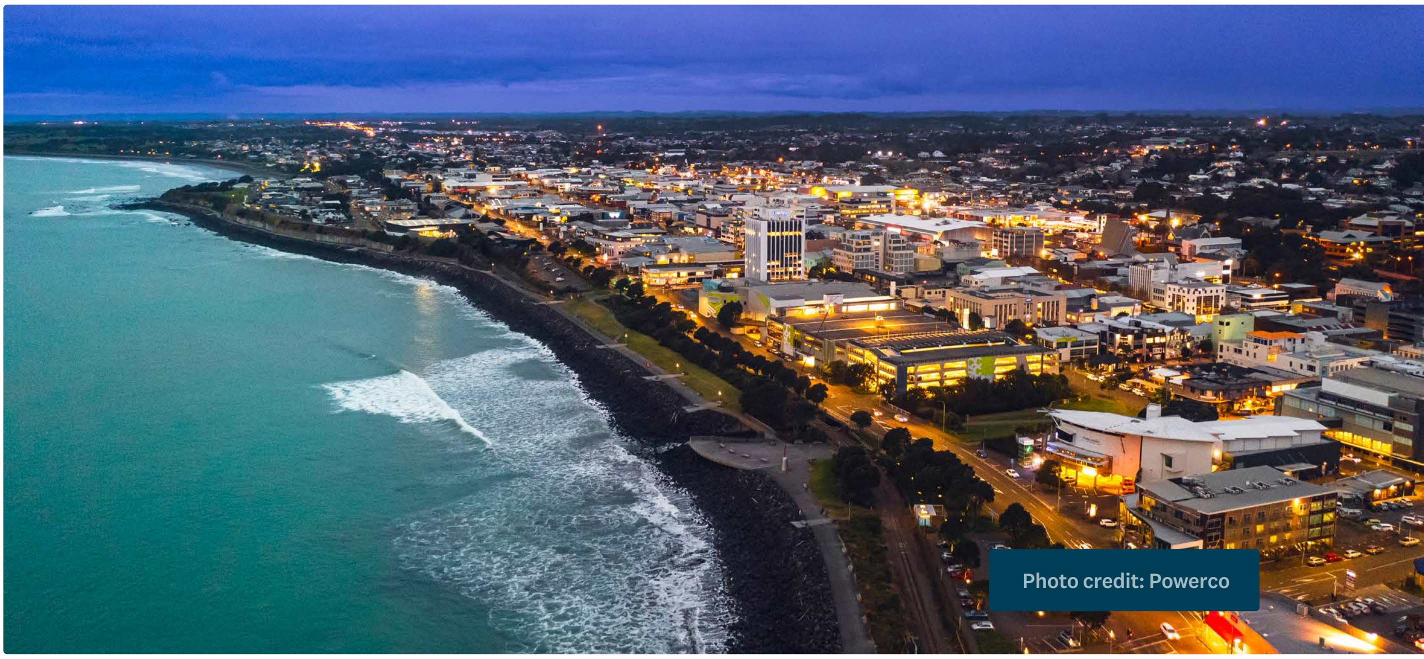


Photo credit: Powerco

Three sites have already confirmed its fuel of choice (shaded in blue), representing a demand for 0.24 MW of electricity.

Table 3 – Summary of Taranaki region RETA sites with potential fuel switching requirements.

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Ministry of Health Hāwera Hospital	**Commercial**	**Confirmed**	**--**	**0.08**
South Taranaki District Council Hāwera Aquatic Centre	**Commercial**	**Confirmed**	**--**	**0.07**
Ministry of Education Waverley Primary School	**Commercial**	**Confirmed**	**--**	**0.09**
Methanex Motunui	Industrial	Unconfirmed	n/a	**40**
Ballance Agri-Nutrients Ltd Kapuni	Industrial	Unconfirmed	n/a	**317.28**
Fonterra Limited Whareroa[4]	Dairy	Unconfirmed	**1,533.50 (213.52)**	**87.29**
Fonterra Limited Kapuni	Dairy	Unconfirmed	**453.2 (63.10)**	**45.63**
Taranaki By-Products Hawera	Meat (with rendering)	Unconfirmed	**149.69 (20.84)**	12.47
Mckechnie Aluminium Solutions Limited Bell Block	Industrial	Unconfirmed	n/a	**4.67**
ANZCO Foods Eltham	Meat processing	Unconfirmed	34.01 (4.73)	**0.4**
Silver Fern Farms Limited Hawera	Meat processing	Unconfirmed	n/a	**1.47**
Ministry of Health Taranaki Base Hospital	Commercial	Unconfirmed	n/a	**0.56**
Fonterra Limited Eltham Collingwood St	Dairy	Unconfirmed	**9.60 (1.34)**	1.44
New Plymouth District Council Wastewater treatment plant	Industrial	Unconfirmed	**18.91 (2.63)**	3.49
Fonterra Brands Limited Eltham Bridge St	Dairy	Unconfirmed	29.07 (4.05)	**5.79**
ANZCO Foods Waitara	Meat processing	Unconfirmed	12.15 (1.69)	**0.71**
Silver Fern Farms Limited Waitotara	Meat processing	Unconfirmed	n/a	**0.54**

[4] At this site, two projects have biomass as optimal fuel and another two have electricity, hence both options are shaded.

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Taranaki Abbattoir Stratford	Meat (with rendering)	Unconfirmed	**5.84 (0.81)**	0.83
Little Knoll Greenhouses Ltd Patea	Horticulture	Unconfirmed	n/a	**0.28**
La Nuova Inglewood	Commercial	Unconfirmed	**9.98 (1.39)**	0.73
Downer New Zealand Limited New Plymouth Bitumen	Industrial	Unconfirmed	n/a	**1.71**
Ministry of Education Stratford High School	Commercial	Unconfirmed	n/a	**0.25**
Downer New Zealand Limited New Plymouth Asphalt	Industrial	Unconfirmed	**4.87 (0.68)**	n/a
New Plymouth District Council Todd Energy Aquatic Centre	Commercial	Unconfirmed	n/a	**0.24**
Tegel New Plymouth	Meat processing	Unconfirmed	**31.5 (4.39)**	2.84
New Plymouth District Council Puke Ariki	Commercial	Unconfirmed	n/a	**0.12**
State-integrated school Francis Douglas Memorial College	Commercial	Unconfirmed	n/a	**0.09**
New Plymouth District Council Len Lye Centre	Commercial	Unconfirmed	n/a	**0.06**
New Plymouth District Council Waitara Pool	Commercial	Unconfirmed	n/a	**0.06**
New Plymouth District Council Civic Centre	Commercial	Unconfirmed	n/a	**0.10**
Van Dyck New Plymouth	Industrial	Unconfirmed	n/a	**0.12**
Western Institute of Technology in Taranaki (WITT) Taranaki	Commercial	Unconfirmed	n/a	**0.36**
Tegel Bell Block Feedmill	Meat processing	Unconfirmed	**17.97 (2.50)**	0.64
Taranaki Galvanizers Stratford	Industrial	n/a	n/a	**0.16**
Poppas Peppers 2009 Limited New Plymouth	Horticulture	n/a	n/a	**0.12**
Technix Bitumen Technologies Limited Port Taranaki	Industrial	n/a	n/a	**0.78**

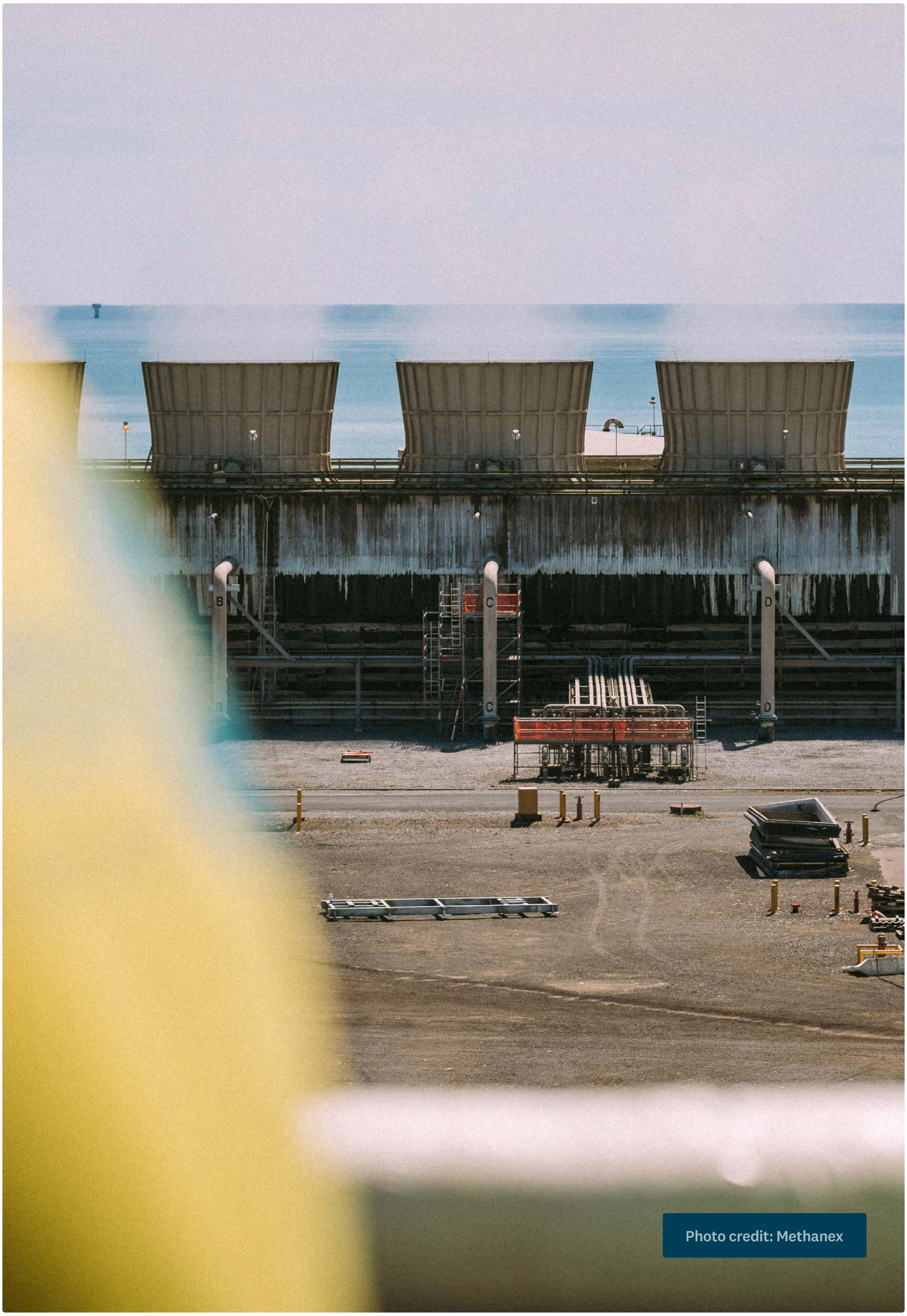


Photo credit: Methanex

5 Simulated decarbonisation pathways

There are a range of decision criteria that individual organisations may apply to determine the timing of their decarbonisation investments. Decisions are impacted by available finance, product market considerations, strategic alignment and other factors.

Rather than attempting to model all of these factors for individual process users, we have developed a range of different scenarios, referred to as decarbonisation pathways, that reflect different decision-making criteria that process heat users (who have not confirmed their fuel choice) might use.

Two pathways represent ‘bookends’ that focus exclusively on one of the two fuel options (biomass or electricity) for unconfirmed projects. Two others use a global standard ‘marginal abatement cost’ (MAC), that quantifies the cost to the organisation of decarbonising their process heat, as the decision making criterion. This is expressed in dollars per tonne of CO_2e reduced by the investment and allows us to determine the timing of the investment as being the earliest point when a decarbonisation decision saves the process heat user money over the lifetime of the investment – the point in time that the MAC of the project is exceeded by the expected future carbon price.

The pathways used in the analysis are as follows:

Pathway name	Description
Biomass Centric	All unconfirmed site fuel switching decisions proceed with biomass, where possible, in 2049 (in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act.
Electricity Centric	All unconfirmed fuel switching decisions proceed with electricity, where possible, in 2049 (in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act.
BAU Combined[5]	All unconfirmed fuel switching decisions (i.e. biomass or electricity) are determined by the lowest MAC value for each project and take place in 2049 (i.e. the same timing as for the fuel-centric pathways).
MAC Optimal	Each site switches to a heat pump or switches its boiler to the fuel with the lowest MAC value for that site. Each project is timed to be commissioned in the first year when its optimal MAC value first drops below a ten-year rolling average of the future NZ Treasury's shadow carbon prices. If the MAC does not drop below the ten-year rolling average before 2049, then the timing based on the fuel-centric pathway is used.

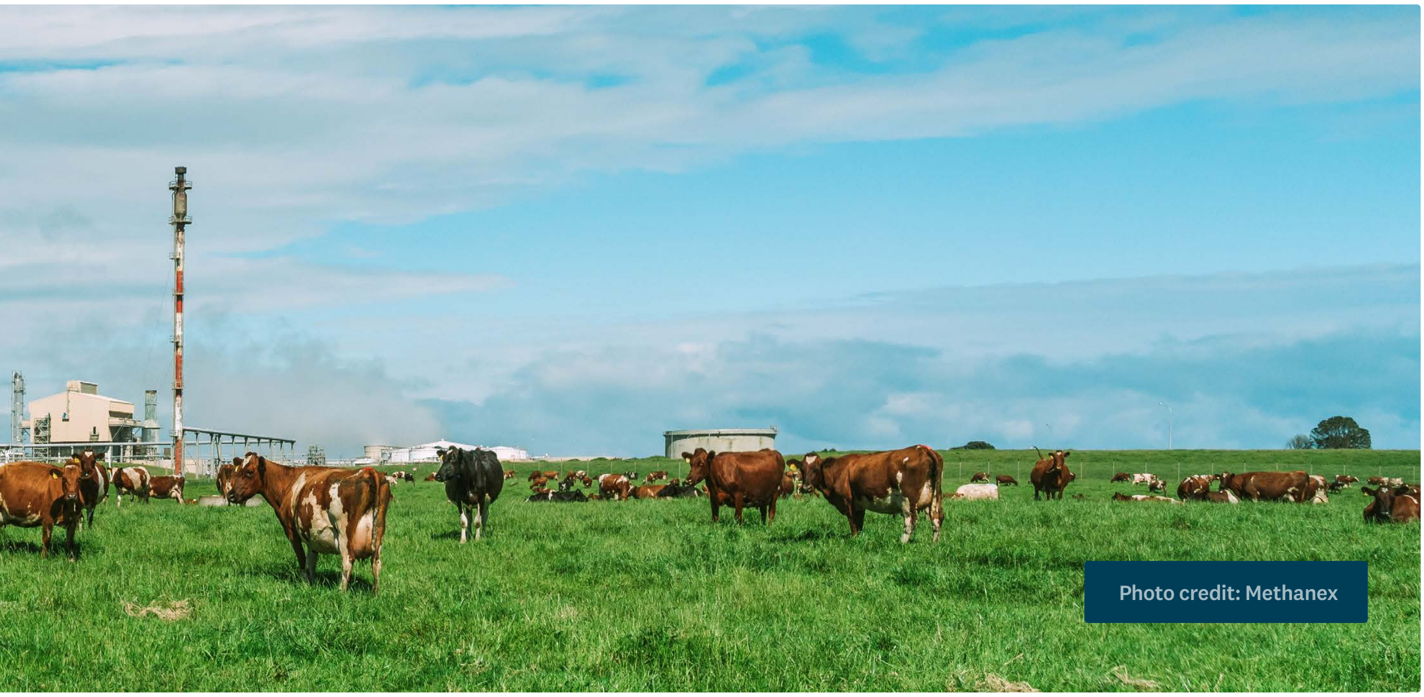


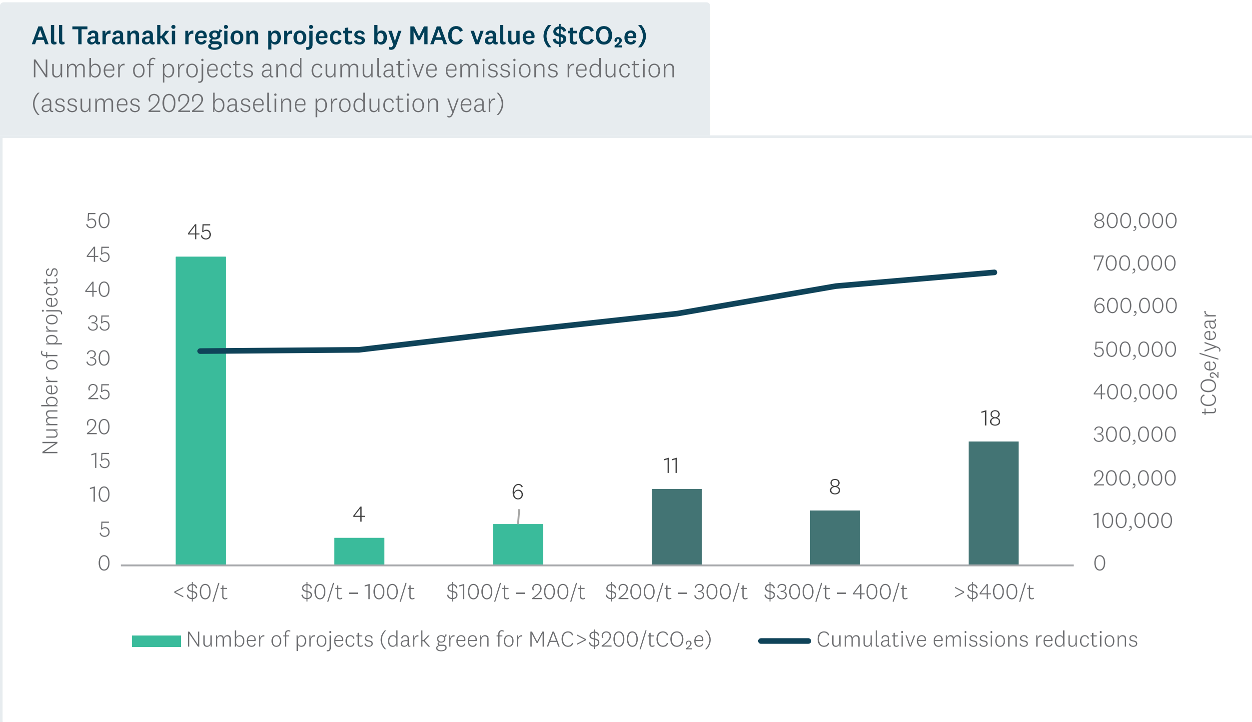
Photo credit: Methanex

5 'BAU' in this case for Taranaki means that all unconfirmed fuel switching projects take place in 2049. We acknowledge that some projects could go ahead earlier in line with the National Direction for GHGs from Industrial Process Heat, which requires emissions plans submitted with resource consents to include an assessment of any 'technically feasible and financially viable lower-emissions alternatives.' https://environment.govt.nz/assets/publications/climate-change/National-Direction-for-Greenhouse-Gas-Emissions-from-Industrial-Process-Heat-Industry-Factsheet.pdf

5.1 Even without a carbon price, 39% of emissions reductions from RETA projects are economic[6]

Using the biomass and electricity costs presented in Section 6 and Section 7, Figure 4 summarises the resulting MAC associated with each decision, and the emissions reduced by these projects.

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



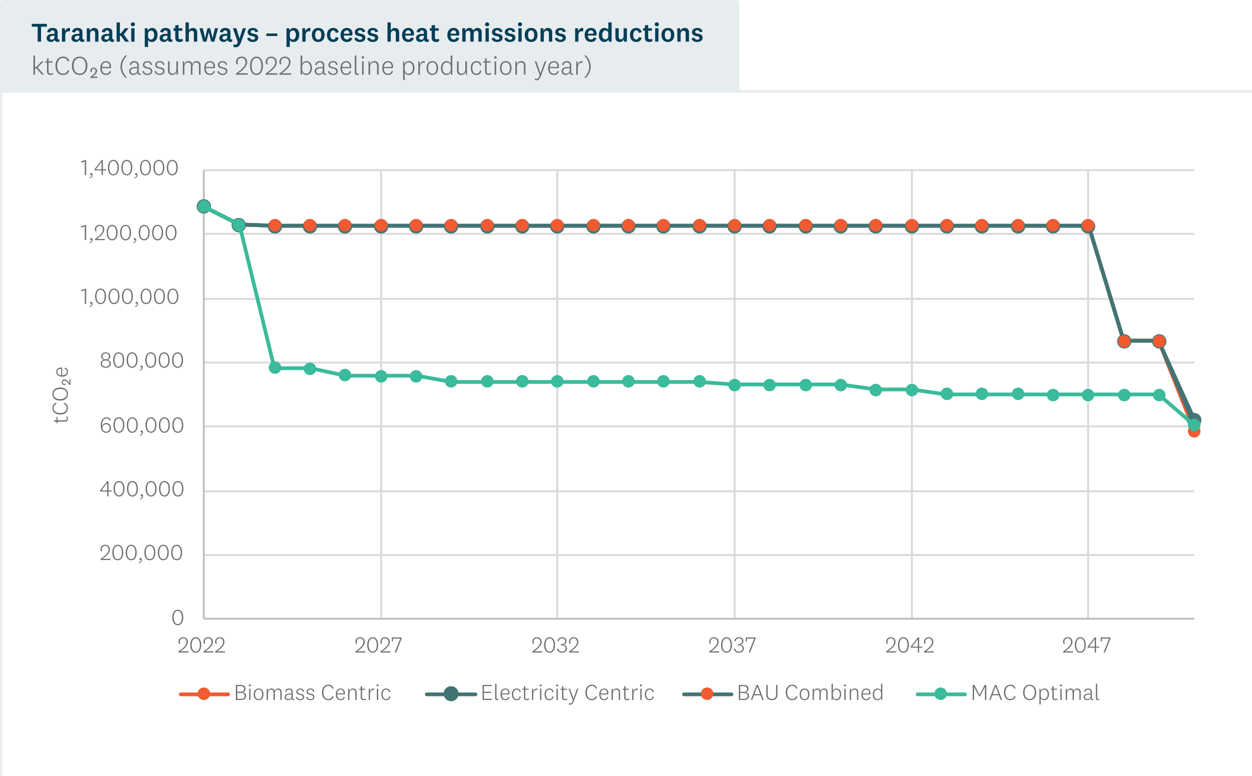
Out of 1,287ktCO_2e of process heat emissions from Taranaki RETA sites, 500ktCO_2e (39% of emissions) have a MAC less than zero, while a total of 578ktCO_2e (45% of emissions) have marginal abatement costs less than $200/t$CO_2$e. Using a commercial MAC decision-making criterion, combined with expected future carbon prices (MAC Optimal), it would be commercially favourable to execute these projects over the next ten years.

Compared to a scenario where each of these projects was executed based on the organisations' current plans (a BAU pathway), the MAC Optimal scenario would accelerate decarbonisation, and reduce the release of long-lived emission by a cumulative 1,450ktCO_2e over the period of the RETA analysis to 2050 (Figure 5).[7]

[6] 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). 44 RETA projects (constituting 39% of RETA Taranaki's process heat emissions) have a Marginal Abatement Cost less than zero.

[7] Note that the Electricity Centric and Biomass Centric pathways are obscured in the chart by the BAU Combined pathway.

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



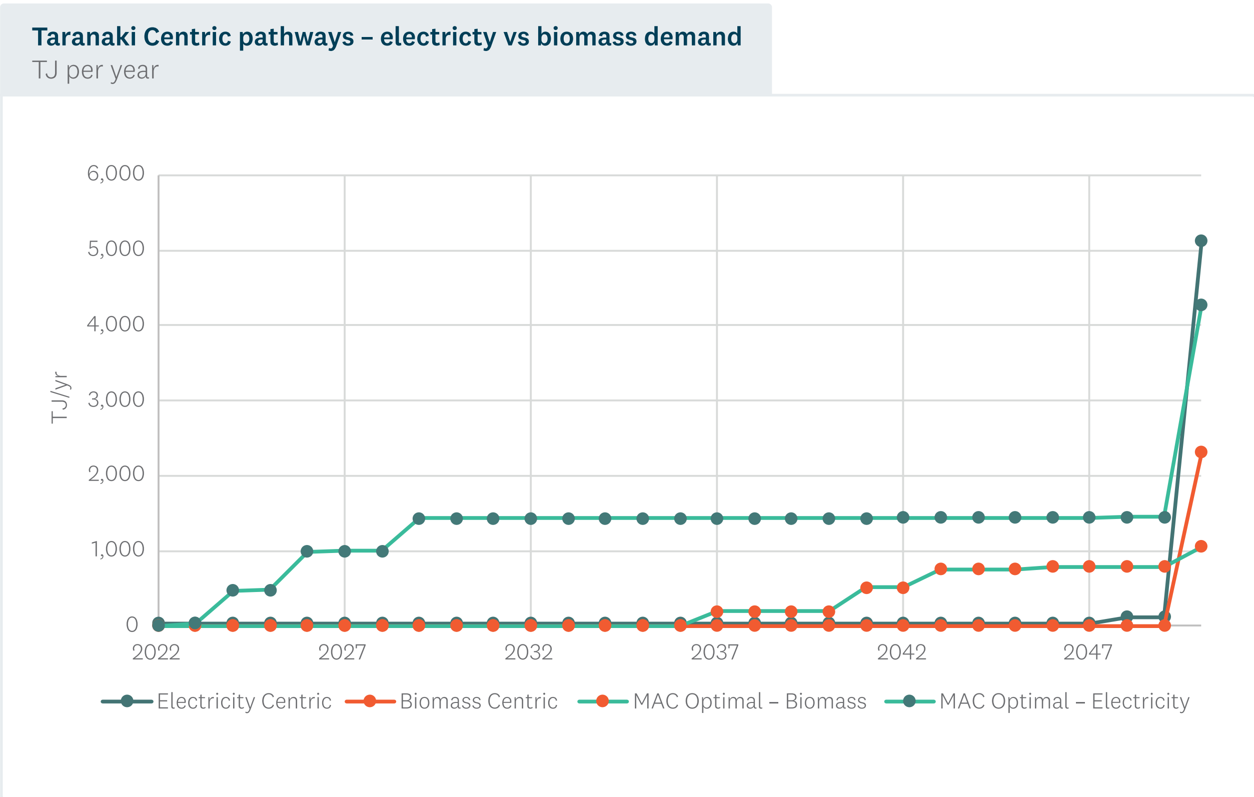
The MAC Optimal pathway proceeds faster, with the majority of emissions reductions economic immediately, primarily as a result of a large number of demand reduction and heat pump projects which are economic at today's carbon prices.

5.1.1 Pathway implications for electricity and biomass demands

The MAC Optimal pathway sees fuel decisions that result in 80% of the energy needs in 2050 supplied by electricity, and 20% supplied by biomass (Figure 6).

We expand further on these fuel switching outcomes in Sections 6 and 7.

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



It is important to recognise the significant impact that demand reduction and heat pump efficiency projects have on the overall picture of Taranaki process heat decarbonisation. As shown in Figure 3, investment in demand reduction and heat pumps meets 31% of energy demands from Taranaki process heat users in 2022, which in turn reduces the necessary fuel switching infrastructure required: thermal capacity required from new biomass and electric boilers would be reduced by 399MW if these projects were completed.[8] We estimate that demand reduction and heat pumps would avoid investment of between $480M and $620M in electricity and biomass infrastructure.[9]

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

9 On the assumption that 1MW of electrode boilers, and associated network connections, or 1MW of biomass boilers, cost on average $1.55M and $1.2M, respectively.

5.1.2 Gas sensitivities

A range of sensitivities have been tested in the modelling, including electricity, biomass and carbon prices and are discussed in the main report. Given the importance of gas in Taranaki the current constraints in supply, additional analysis of the sensitivity to gas prices was undertaken.

To determine the sensitivity from an energy-only demand perspective, the sensitivity analysis excluded sites that also use natural gas as feedstock. However, we recognise that changes in natural gas prices will significantly affect demand from sites that also use the fuel as feedstock.

The modelling assumed a base gas price of $18.02/GJ ($0.065/kWh) for industrial process heat users (based on the mid-point of MBIE estimates for commercial and industrial users). As shown in Figure 7, we found that halving the annual escalator for natural gas from 3% to 1.5% resulted in 533ktCO_2e of additional emissions on a cumulative basis through to 2050. By contrast, doubling the escalator to 6% accelerated 23 projects, delivering an additional 834ktCO_2e emissions reduction by 2050. A significant increase in the natural gas price to $45/GJ by 2035 (excluding ETS charges) for all users accelerated 24 projects with a cumulative additional reduction of 1,012ktCO_2e by 2050.

Figure 7 – Sensitivity of emissions reduction pathways to different gas price assumptions. Source: EECA

Taranaki pathways – process heat emissions reductions
tCO_2e (assumes 2022 baseline production year; excludes sites using natural gas as feedstock)

6 Biomass – resources and costs

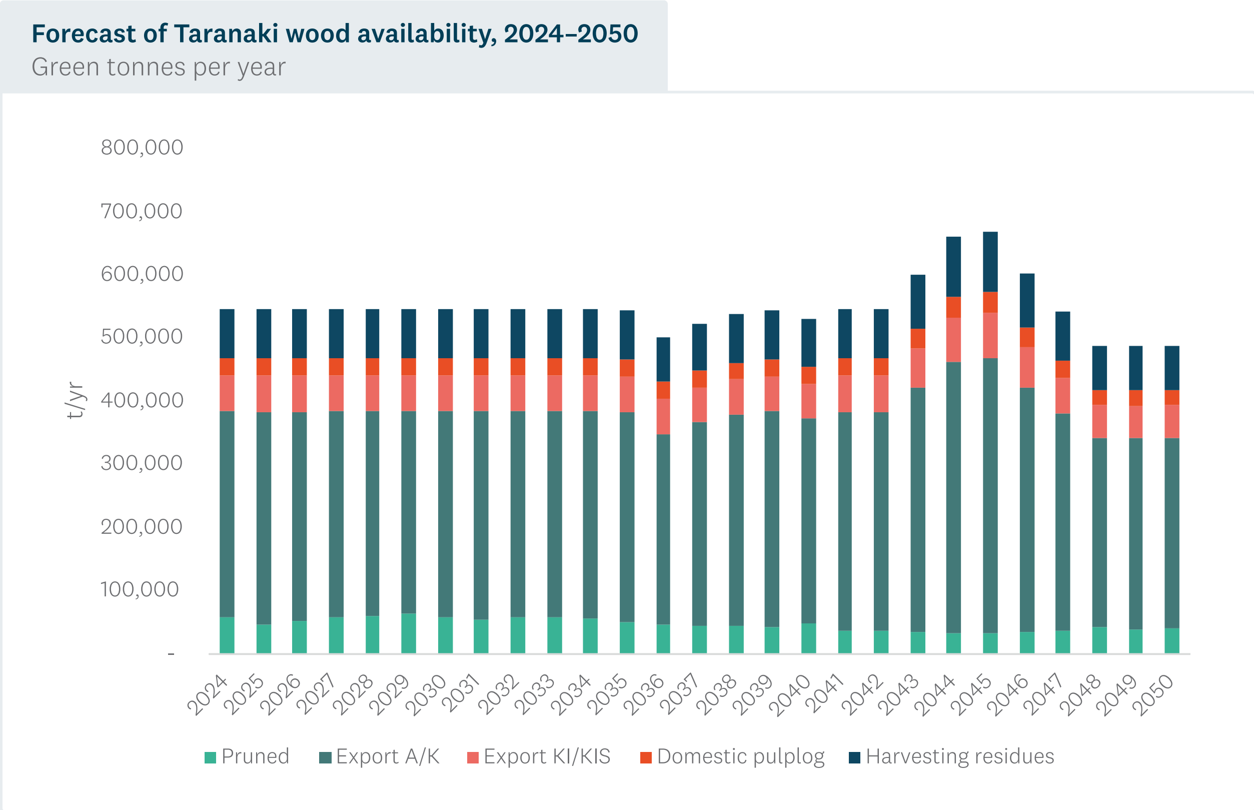
To assess the total availability of harvestable wood in the Taranaki region, both a top-down and bottom-up analysis has been undertaken. The bottom-up analysis is based on interviews with major forest owners, as forest owners' actual intentions will often deviate from centralised forecasts due to changes in log prices and other dynamic factors. It also provides an assessment of where the wood is expected to flow through the supply chain – via processors to domestic markets, or export markets, as well as volumes that are currently being utilised for bioenergy purposes. This analysis allows us to estimate practical levels of sustainably recoverable woody residues.

A top-down analysis suggests that an average of around 550kt pa (3,950TJ pa) of wood will be harvested in the Taranaki region over the next 15 years.[10]

Photo credit: Taranaki Pine

[10] We use 15 years as a reasonable assessment of the near-term period that process heat users considering biomass would likely want to contract for, if they were making the decision in the next few years.

Figure 8 – Wood resource availability in Taranaki region, 2024-2050. Source: Forme



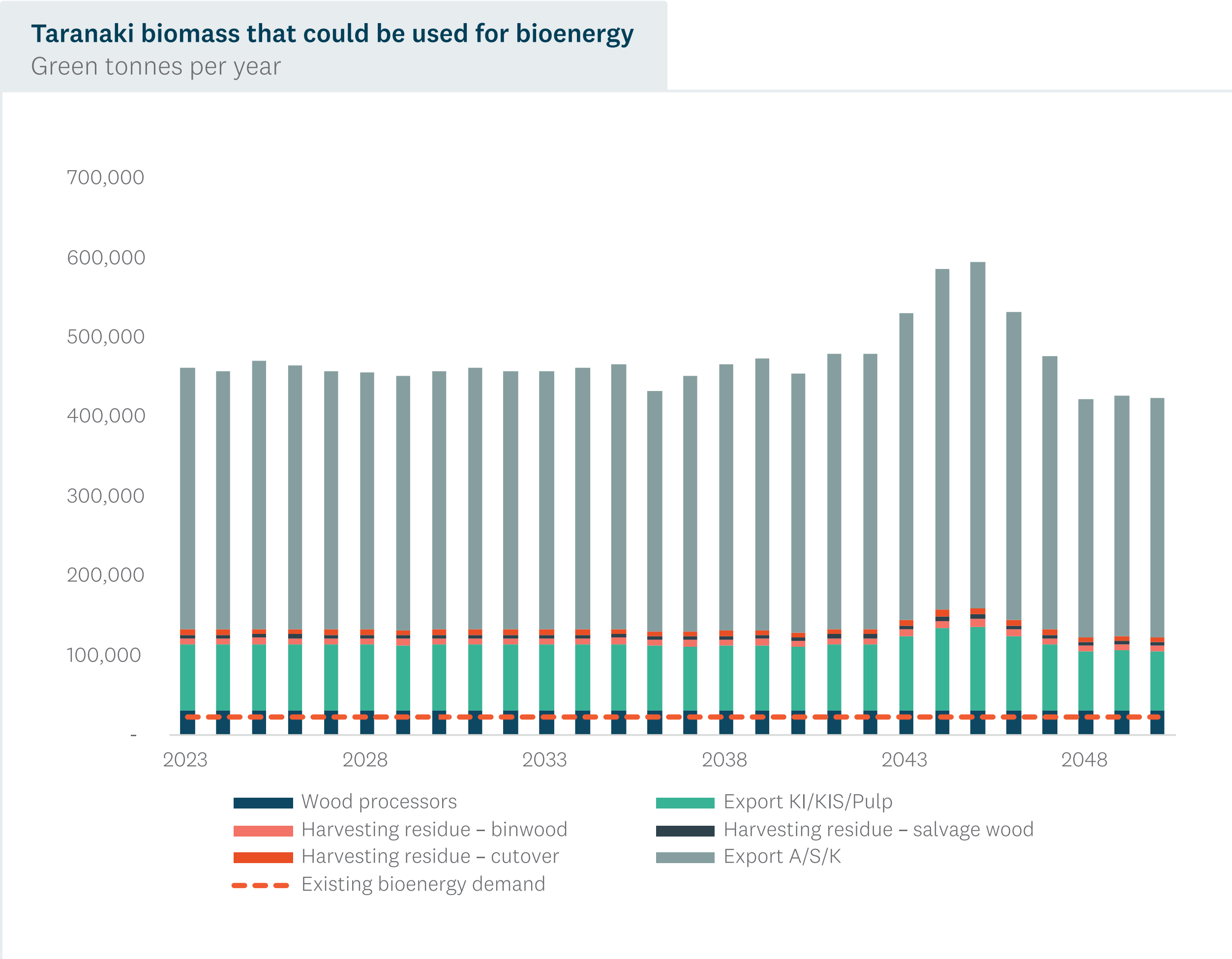
A more comprehensive view of resource availability, that combines the top-down and bottom-up analyses, reveals the potential volumes that could be available for bioenergy. This analysis finds that:

- On average, 19kt pa (136TJ pa) of harvest residues could be available for bioenergy. Around 13kt pa (90TJ pa) is currently being recovered (binwood and salvage wood), while the rest is not currently utilised (mainly cutover residues).
- Interviews with sawmills suggested that around 53kt (382 TJ) per year of processing residues are produced (mostly woodchip) of which 24kt (170TJ) per year is already used for bioenergy.[11] Most of the woodchip (22kt or 158 TJ per year) was exported to a pulp mill in central North Island (although this mill has since ceased operating); the remaining residues (7kt or 51 TJ per year) could be made available for new process heat users.
- On average through to 2038, 83kt (599TJ) per year of domestic pulp/firewood and export KI/KIS logs is available.

The resulting potential volume for bioenergy is shown in Figure 9.

[11] This is data for 2023.

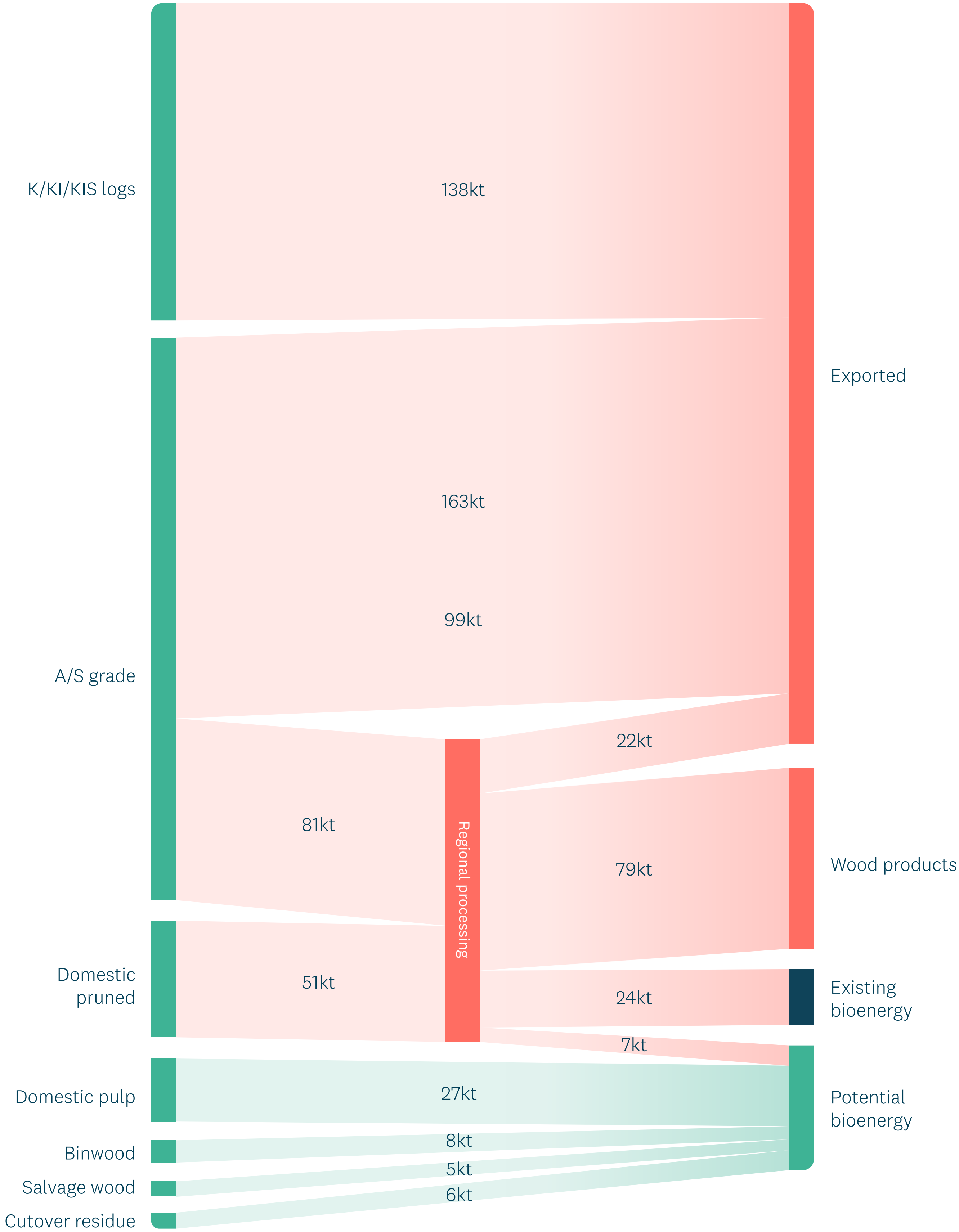
Figure 9 – Assessment of available Taranaki woody biomass that could be used for bioenergy. Source: Forme



The overall analysis of the Taranaki region is summarised in Figure 10.

Photo credit: Taranaki Pine

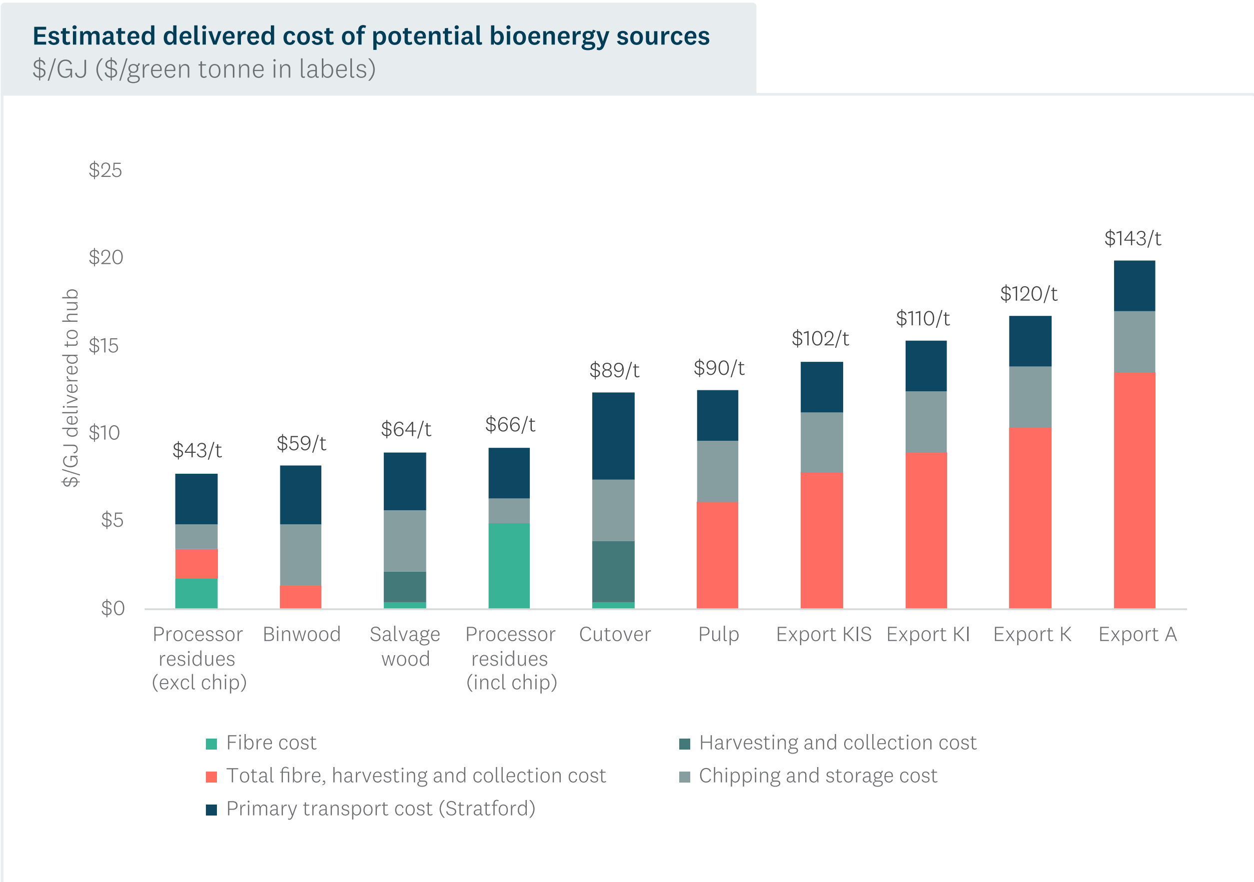
Figure 10 – Average wood flows over 15 years in Taranaki region. Source: Forme



Overall, EECA estimates that, on average over the next 15 years, **approximately 53kt per year (382TJ) of Taranaki woody biomass is currently unutilised and could be recovered for new boiler demands without disrupting low grade export markets or existing bioenergy consumers**. However, this average disguises a significant variance in the annual availability .

The costs of accessing this biomass, and delivering it to the process heat user's site, is presented in Figure 11.

Figure 11 – Estimated delivered cost of potential Taranaki bioenergy sources. Source: Forme



Export grade A and K logs have been retained in this analysis to represent 'scarcity values' if the scenario analysis indicates that other more plausible and sustainable sources of bioenergy are insufficient. However, we do not believe these are sustainable or practical sources of bioenergy.

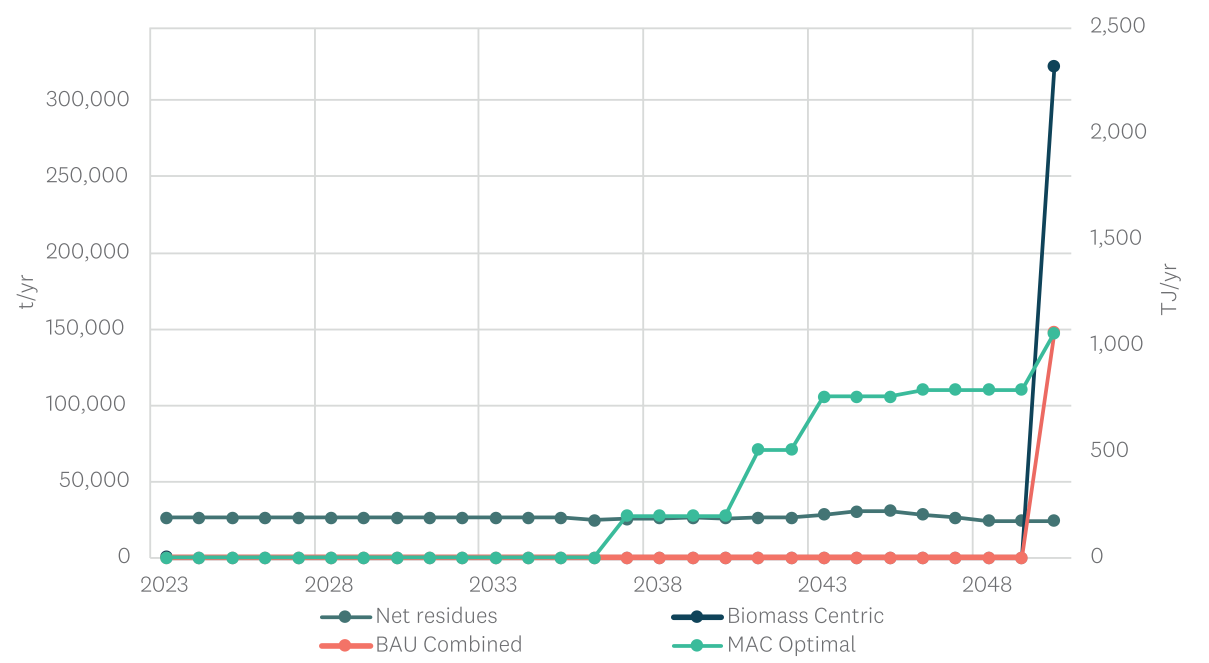
6.1 Impact of pathways on biomass demand

Our analysis shows the growth in biomass demand (in both tonnes and TJ per year) arising from each of the decarbonisation pathways, against the expected available residues (net of existing demand) (Figure 12).

Expected harvesting and processor residues are only sufficient to meet the MAC Optimal biomass demand until around 2037. After that point, either residues would have to be imported from another region, or more expensive pulp or KI/KIS grade logs would need to be diverted from their export markets, at an estimated cost of $15/GJ (including transport to a central hub and chipping/storage). By 2050, both the MAC Optimal and Biomass Centric pathways require diversion of costly Export K or A logs to bioenergy.

Figure 12 – Growth in biomass demand from Taranaki pathways. Source: EECA

Taranaki pathways – biomass demand and available residues
Green tonnes and TJ per year



The degree to which these resources are used is a commercial decision, which would include a comparison with alternatives in terms of cost, feasibility, and desirability. Depending on the process heat users' preference of fuel type some types of resources may not be suitable. In some situations, higher cost pellets may be required, which in turn require higher-grade raw material.

7 Electricity – network capacity and costs

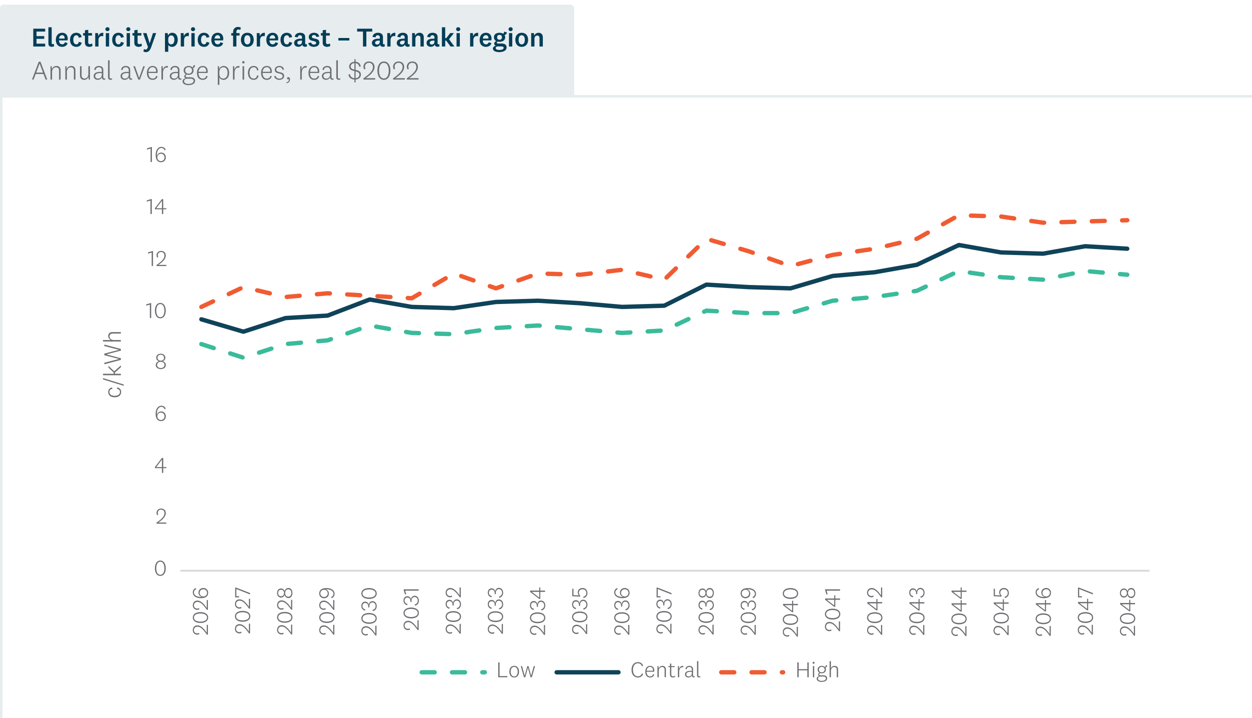
The availability of electricity to meet the demand from process heat users is largely determined at a national 'wholesale' level. Supply is delivered to an individual site through electricity networks – a transmission network owned by Transpower, and a distribution network owned by electricity distribution businesses (EDBs), that provides power to individual consumers. The EDBs connect to the transmission network at 'grid exit points' (GXPs). There is one EDB serving the Taranaki region – Powerco.

The price paid for electricity by a process heat user is made up of two main components:[12]

- A price for 'retail electricity' – the wholesale cost of electricity generation plus costs associated with electricity retailing.
- A price for access to the transmission and distribution networks.

As shown in Figure 13, the forecast price of retail electricity (excluding network charges) is expected to increase (in real terms) from 10c/kWh in 2026 to 11c/kWh in 2037 under a 'central' scenario. However, different scenarios could see real retail prices higher or lower than that level by 2037.

Figure 13 – Forecast of real annual average electricity price for large commercial and industrial demand in the Taranaki region. Source: EnergyLink



[12] Other smaller components include metering and regulatory levies.

Beyond 2037, this forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing out to 2050. 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.

EDBs charge electricity consumers for the use of the existing distribution network. In addition, where the connection of new electric boilers requires EDBs to invest in distribution network upgrades, the cost of these can be paid through a mix of ongoing network charges, and an up-front 'capital contribution'. Powerco maintains a policy that governs the degree of capital contribution, and process heat users need to discuss these with Powerco.

In addition, process heat users who connect new electric boilers directly to Transpower's grid will face equivalent transmission charges, as determined under the Transmission Pricing Methodology (TPM). Process heat users who connect to the Powerco's network will also face a share of these transmission costs, as determined by Powerco's pricing methodology.

Powerco set their distribution charges for large commercial and industrial customers based on the size of the connection (kVA) and peak coincident demand (kW). As such distribution prices will vary per site. In addition, transmission charges are a combination of capacity (kVA) and average demand (kW) charges. Our modelling approximates these charges for each site.

Transpower and Powerco 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.[13] The timing of demand growth (that drives this investment) is uncertain, which results in a challenging decision-making environment for network companies. As we recommend below, it is important that process heat users considering electrification keep Powerco abreast of their intentions.

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

- The current 'spare capacity' (or headroom) and security of supply levels in Transpower and Powerco's networks to supply electricity-based process heat conversions.
- The cost of any upgrades required to accommodate the demand of a process heat user, considering seasonality and the user's ability to be flexible with consumption, as well as any other consumers looking to increase electricity demand on that part of the network.
- The timeframe for any network upgrades (e.g. procurement of equipment, requirements for consultation, easements and regulatory approval).
- The price paid for electricity to an electricity retailer (or direct to the wholesale market, for large sites), and any other charges paid by electricity consumers (e.g. use-of-network charges paid to Powerco and Transpower).
- The level of connection 'security' required by the site, including its ability to tolerate any rarely occurring interruptions to supply, and/or the process heat user's ability to shift its demand through time in response to a signal from the network or the market. This flexibility could reduce the cost of connection, and the supply costs of electricity.

[13] While this RETA analysis only examines demand from process heat electrification this broader context of potentially rapid growth in demand is important to understanding the challenges associated with accommodating new load.

For the majority of 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. Our estimates suggest most of these minor upgrades would have connection costs under $1M (and around half the sites for under $300,000) and have connection lead times of less than 12 months.

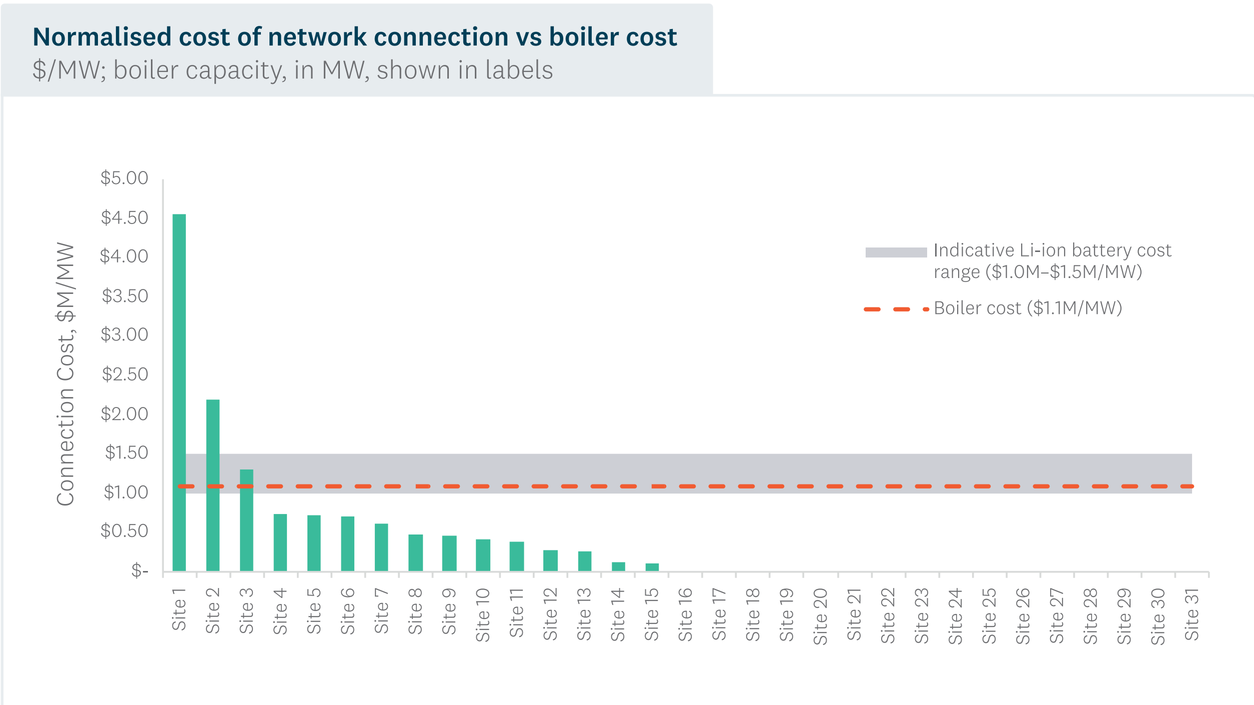
More substantial upgrades to the distribution network are required for two sites, with commensurately higher estimated costs (mostly between $3M and $20M per stage, dependent on the level of security) and longer lead times (12-48 months).

A further two sites may require major distribution and transmission upgrades, depending on level of network security required. The cost of these upgrades may reach $16M for one site and up to $82M for the other (which includes a number of stages) and may take up to 48 months per stage to execute.

The costs of connection can be a significant part of the overall capital cost associated with electrifying process heat demand, and process heat users need to engage with EDBs to discuss connection options and refine the cost estimates we have included in this report.

As highlighted above, around half of the sites considering electrification can be connected to the network at minimal cost. For the remaining sites, Figure 14 shows each site’s connection costs expressed in per-MW terms, i.e. relative to the capacity of the proposed boiler.

Figure 14 – Normalised cost of network connection vs boiler cost, Taranaki RETA sites. Source: Ergo, EECA



The red dashed line in Figure 14 compares these per-MW costs to the estimated cost of an electrode boiler ($1.1 million per MW). We note that these costs represent the total construction costs of the expected upgrades. The degree to which process heat users need to make capital contributions to these upgrades depends on a variety of factors and needs to be discussed with Powerco.

The timeframes for connection above assume these investments do not require Transpower or Powerco to obtain regulatory approval. We note that if connections also rely on wider upgrades to the network, Powerco would have to seek regulatory approval for these investments, which could also add to the timeline.

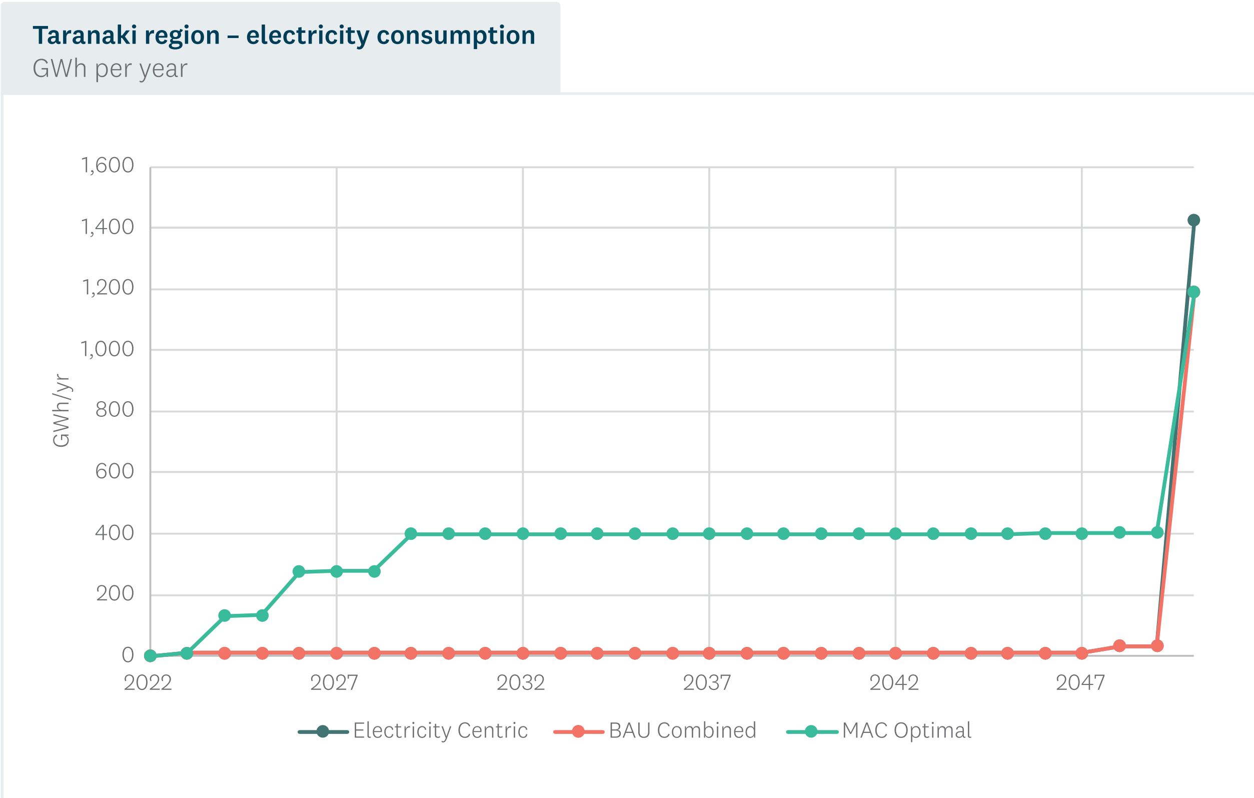
The costs provided above are indicative and appropriate for a screening analysis. They should be further refined in discussion with network owners, and the final costs in some situations will depend on the collective decisions of a number of sites who may require access to similar parts of the network.

Photo credit: Powerco

7.1 Impact of pathways on electricity demand

Figure 15 shows the pace of growth in electricity consumption under the different pathways.

Figure 15 – Growth in Taranaki electricity consumption from fuel switching pathways. Source: EECA



The Electricity Centric pathway, where all unconfirmed sites choose electricity, would result in a significant (140%) increase in the annual consumption of electricity in the region, although this wouldn't occur until 2050 (and is unlikely to occur all at once as it is shown in Figure 14). In the MAC Optimal and BAU Combined pathways, electricity consumption in Taranaki would still grow by 1,200GWh by 2050 (120%). In the MAC Optimal pathway, around a third of this growth would be observed by 2030.

Powerco's investments will be driven more by increases in peak demand than by growth in consumption over the year. Figure 16 shows how the different pathways affect peak demand across the local network.

Figure 16 – Potential Taranaki peak electricity demand growth under different pathways.

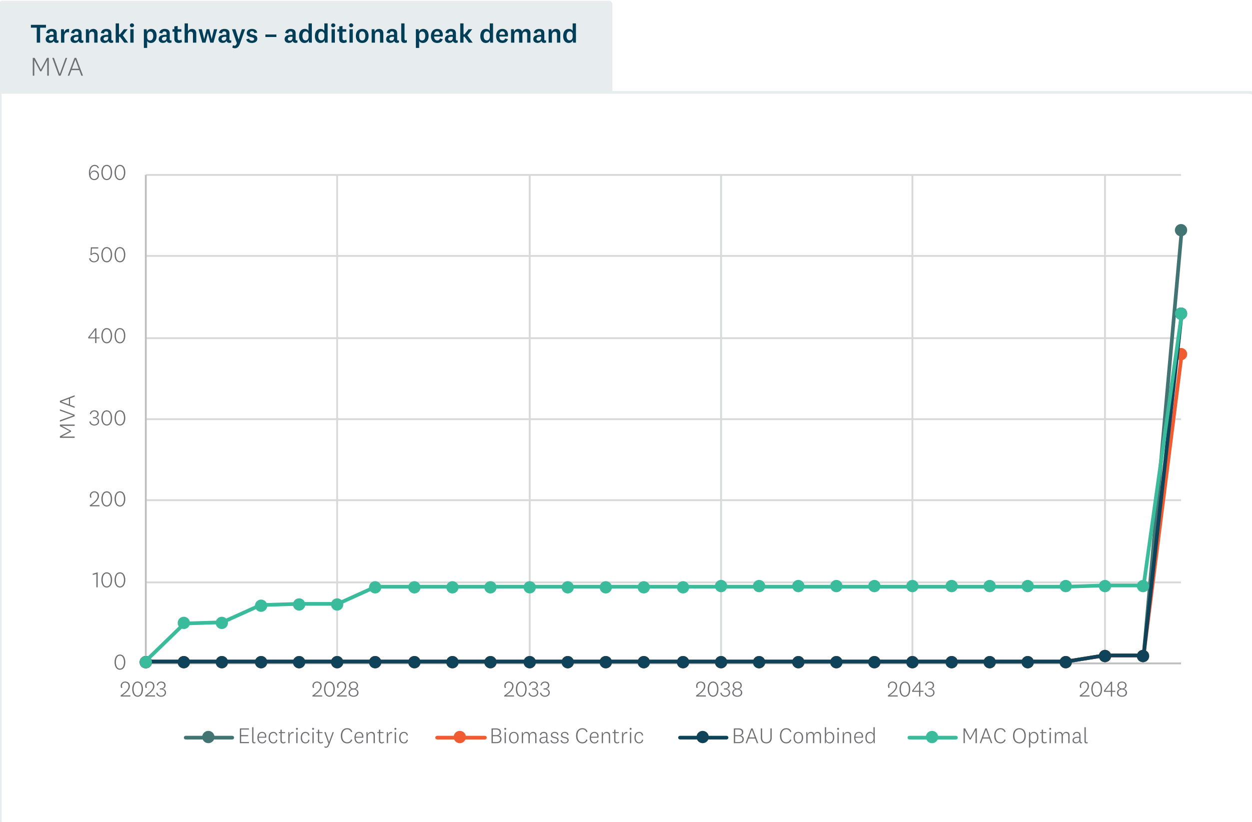


Figure 16 illustrates that, should all unconfirmed process heat users in Taranaki convert to electricity (the 'Electricity Centric' pathway), the increase in demands could be significant. If all sites reached their maximum outputs at the same time, the increase in instantaneous electricity demand would be 232MW by 2050, an increase of 127% compared to today. If a potential hydrogen electrolyser project also went ahead, this would add a further 300MW to this increase in peak demand.

Table 4 breaks down the costs to Powerco. Due to the significant cost associated with the connection of potential hydrogen electrolysers, we have reported the costs associated with these projects separately from other electrification projects.

Table 4 – 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)
Hydrogen projects (in 2050)	302	$273	302	$273
Other electrification projects[14]	230	$161	127	$50
Powerco total	532	$434	429	$323

[14] This includes both confirmed and unconfirmed projects.

Between $323M and $434M will be spent connecting new process heat plant to the local networks, depending on the pathway. However, a substantial portion of this cost ($273M) relates to hydrogen electrolysers.

Note that the network upgrade costs presented in Table 4 may not necessarily reflect the connection costs paid by process heat users, as they may be shared between Powerco and the new process heat user. The degree of sharing ('capital contributions') depends on the policies of Powerco.

Photo credit: Powerco

7.2 Opportunity to reduce electricity-related costs through flexibility

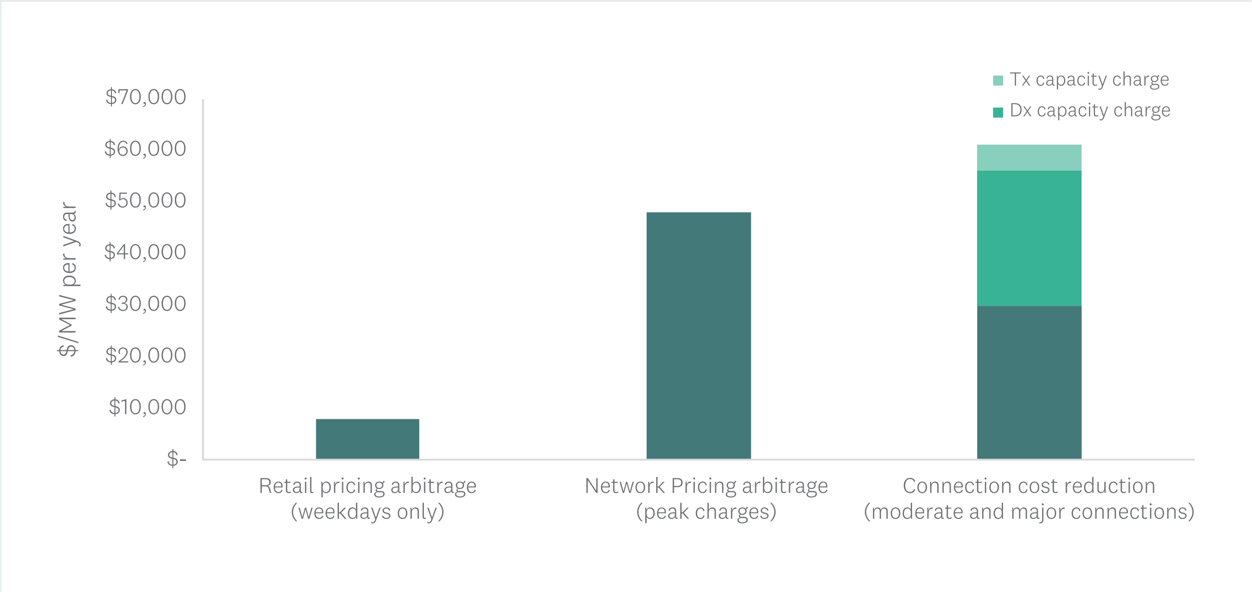
Process heat flexibility can improve system resilience and reduce both electricity system costs and process heat electricity-related costs.

Analysis was carried out to illustrate the potential cost savings associated with enabling flexibility in process heat demands, showing what this flexibility could be worth to a process heat user, per MW of demand that can be shifted into an off-peak period.[15]

As shown in Figure 17, Taranaki process heat users could potentially reduce their electricity procurement costs by up to $56,000 per MW of flexibility deployed every year (Figure 16). In addition, at the planning stage, they could also reduce costs associated with the size of their connection to the electricity network – the investment required in the physical connection, as well as any network charges from Powerco that relate to the size of the connection. We estimate that this could provide an additional reduction in cost of $61,000 (annualised), if it allows them to reduce the size of their connection to the network.

Figure 17 – Estimates of the value of flexibility in Taranaki RETA. Source: EECA

Potential value of reliable flexibility in process heat demand
$/MW



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

15 We note that, in reality, the estimate for reducing connection costs may vary significantly, as the underlying equipment underpinning network investment comes in standard sizes – varying peak process heat demand by a relatively small amount may not change the connection costs.

8 Recommendations

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:

- Although information is improving since the commencement of the RETA programme (nationally), there may still be opportunities to refine the understanding of residue costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and alternative 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 'energy- grade', or E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the development of an 'integrated model' of cost recovery, achieving the best outcomes in terms of recovery cost and volumes.
- Investigate and establish mechanisms to help suppliers and consumers within and outside the region 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. The analysis for Taranaki showed that the cost of biomass can significantly affect investment decisions; given the significant potential demand for biomass relative to available residues in the region (processing and harvest), process heat users would benefit from a mechanism that could help identify opportunities for inter-regional trade of biomass resources.
- 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.
- Undertake research into the likely competing demands for wood fibre from other emerging markets, such as biofuels and wood-derived chemicals.

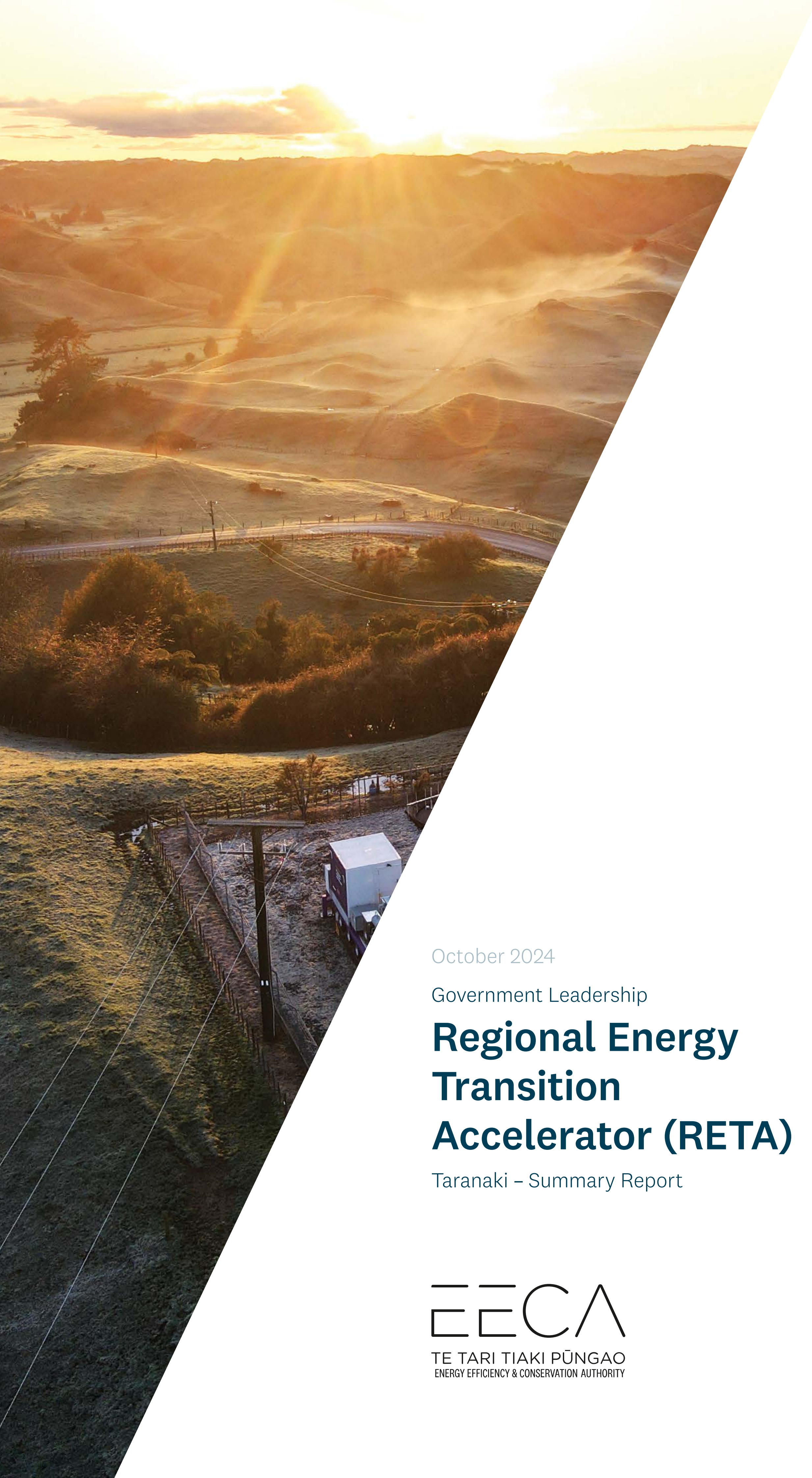
Recommendations to improve the use of electricity for process heat decarbonisation:

- Powerco to proactively engage on process heat initiatives to understand 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. Powerco should ensure Transpower and other stakeholders (as necessary) are aware of information relevant to their planning at an early stage.

- Process heat users to proactively engage with Powerco, keeping them abreast of their plans with respect to decarbonisation, and providing them with the best information available on the nature of their electricity demand over time (baseload and varying components); 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; and any spare capacity the process heat user has onsite. While the costs associated with network connection used in this report have been estimated based on the best publicly available information available to us, when process heat users provide the information above, it will allow EDBs to provide more tailored options and cost estimates.
- Powerco to 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).
- To support this early engagement, Powerco to 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 Powerco, and a network section where Powerco provide high-level options for the connection of the process heat user’s new demand. Information provided by Powerco 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, flexibility aggregators, Powerco and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.
- The electricity sector and process heat users should collaborate to explore and demonstrate flexibility. This is consistent with steps in the FlexForum’s Flexibility Plan.
- Powerco and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.
- EECA 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:

- EECA to work with the Treasury and Ministries (such as Ministry for the Environment) to create an easily-accessible centralised portal that publishes up-to-date carbon price assumptions and scenarios that are used to guide policy and regulatory decisions, e.g. Treasury’s shadow carbon prices used for cost-benefit analysis, Treasury’s ETS price assumptions for fiscal forecasting etc.



October 2024

Government Leadership

Regional Energy Transition Accelerator (RETA)

Taranaki – Summary Report

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY