Pricing Strategy & Roadmap

April 2025

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1. Introduction

Our Pricing Strategy aims to deliver cost-reflective pricing while preserving consumer choice.

This document outlines Alpine Energy's Pricing Strategy and Roadmap for the period 2025–2030. It discusses our approach to achieving cost-reflective, efficient, and fair pricing for the electricity lines service we provide. The strategy addresses our key pricing objectives and details our roadmap to refine pricing structures over the next five years. Through these measures, the roadmap aims to improve network utilisation, support the adoption of emerging technologies, and deliver long-term affordability for consumers while meeting regulatory requirements.

Key Aspects of Our Pricing Strategy

The pricing objectives guiding our structure are:

- Cost-Reflective Pricing: Ensuring pricing aligns with the cost drivers of supply to individual consumer groups.
- Clear Pricing Structure: Providing transparent pricing that is easy for consumers to understand.
- Incentivising Efficient Network Connection and Use: Signalling the economic cost of supply and future congestion to encourage efficient network use.
- Consumer Focus: Engaging with consumers and retailers, managing price shocks, and evaluating the impact of pricing changes.

Aligned with these principles, our pricing structure is designed to recover the costs of building, maintaining, and operating the network, ensuring its reliability for current and future users.

Addressing Network Congestion

To support the objective of incentivising efficient network connection and use, we aim to signal the cost of network congestion to consumers. This approach encourages more informed decisions about energy use during periods of congestion, helping to avoid or delay costly network upgrades. By shifting or reducing consumption during these times, consumers can potentially lower their electricity charges. A detailed overview of network characteristics and constraints is provided below.

Additionally, by signalling the impact of electricity use during periods of network congestion, we promote more efficient energy consumption. This approach supports cost-reflective pricing, empowering consumers to adopt and manage technologies such as electric vehicles and solar systems effectively while reducing the need for expensive network infrastructure expansion.

Transitioning to More Cost-Reflective Pricing

We aim to ensure that all pricing categories expose consumers to prices that fall between the avoidable cost and the stand-alone cost for their specific category. However, we understand that any change needs to be gradual to limit the impact on those who may struggle with affordability. The government's phase-out of the LFC Regulations by April 2027 provides an opportunity to make our pricing more cost-reflective, supporting a fairer and more efficient approach with better alignment across all pricing categories.

Informing Our Approach

Several factors influence how we shape our pricing programme:

- Our 2024 AMP forecasts significant growth on our network over the next ten years. This is driven largely by industrial growth in the Timaru region and the electrification of process heat and transportation across our network. As demand increases, managing the costs of reinforcing the network becomes crucial. Pricing signals will offer consumers the option to either reduce or shift their demand or pay for the additional capacity required. This applies to both accommodating existing load growth and connecting new load, emphasising the importance of consistent and effective use of long-run marginal cost to inform both line charges and connection charges for new load.
- While technologies such as distributed generation and battery storage are not yet significantly impacting our network management, we expect they will play a larger role in the future. As these technologies become more prevalent, it will be important to signal in advance the pricing structures that will encourage their efficient use, particularly when non-network solutions are considered to accommodate future growth.
- We are mindful of how pricing changes may affect our consumers. A gradual transition to new pricing structures can help reduce price shocks and lessen the impact of change for all consumers, especially those who may find higher energy costs more challenging.
- We are aligned with the Government's Emissions Reduction Plan, which focuses on electrifying transport and reducing the use of fossil fuels in homes and businesses.
- Our pricing approach is compliant with the principles set out by the Electricity Authority (EA) and complies with the EA's expectations for distribution pricing reform.

By considering these factors within our pricing strategy, we aim to create a more adaptable and sustainable network that supports the changing needs of our consumers while balancing affordability and efficiency.

2. Network characteristics and network constraint

The Alpine Energy network is served by seven Grid Exit Points (GXPs). Canterbury has the highest concentration of agricultural irrigation in New Zealand, accounting for two-thirds of the country's total irrigation.

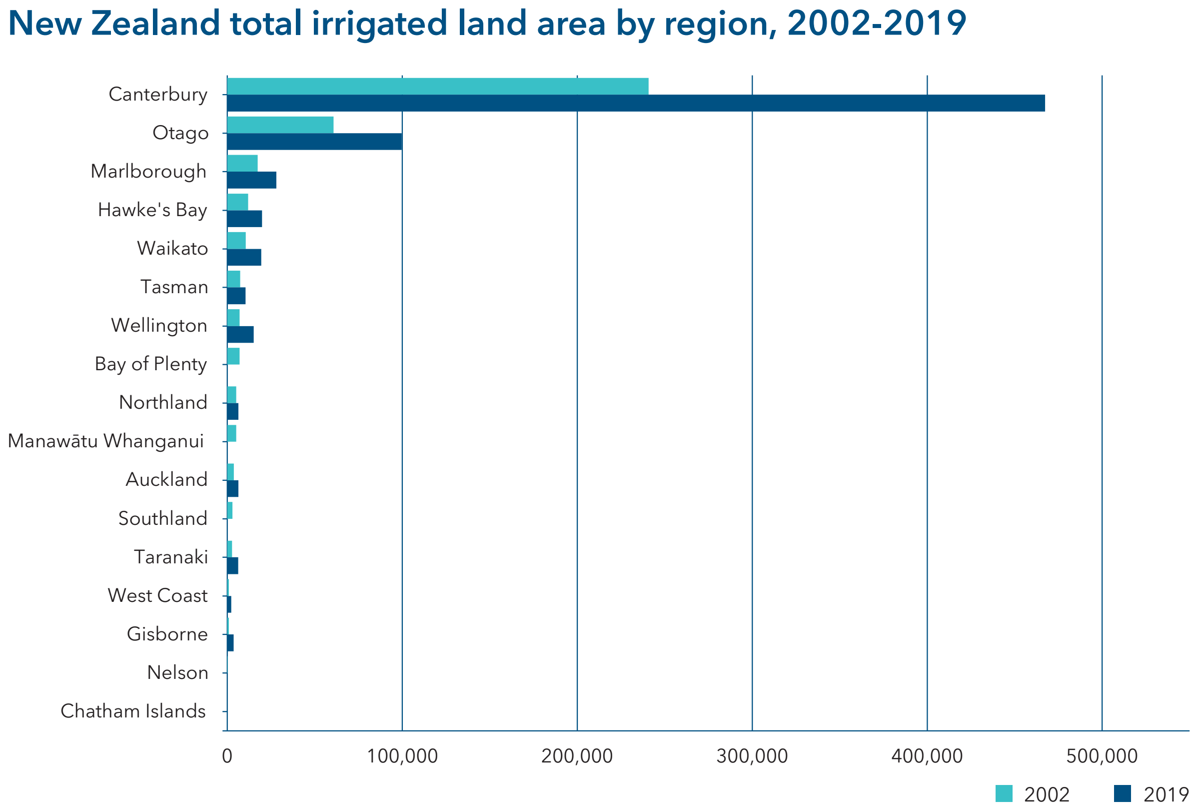


Figure 1: New Zealand total irrigated land area by region, 2002–2019

Source: Stats NZ. ***Irrigated land – published April 2019*** 18 April 2019. https://www.stats.govt.nz/indicators/irrigated-land-published-april-2019/

As a result, our network experiences a distinct seasonal demand pattern, with summer peaks occurring in most years due to irrigation activity. For example, in 2023/24, weekday summer demand was 35% higher than winter demand. High rainfall can moderate summer demand but this seasonal variation indicates that capacity constraints on our network are likely to occur at specific times of the year, as well as during certain hours of the day. Winter peak periods, for instance, typically fall between 7:00 and 9:00 am and 2:00 and 6:00 pm, with an additional spike occurring just after 11:00 pm. The maximum demand for 2023/24 occurred on Thursday, 11 January 2024, between 3:30 and 4:00 pm, significantly exceeding the average summer business day profile.

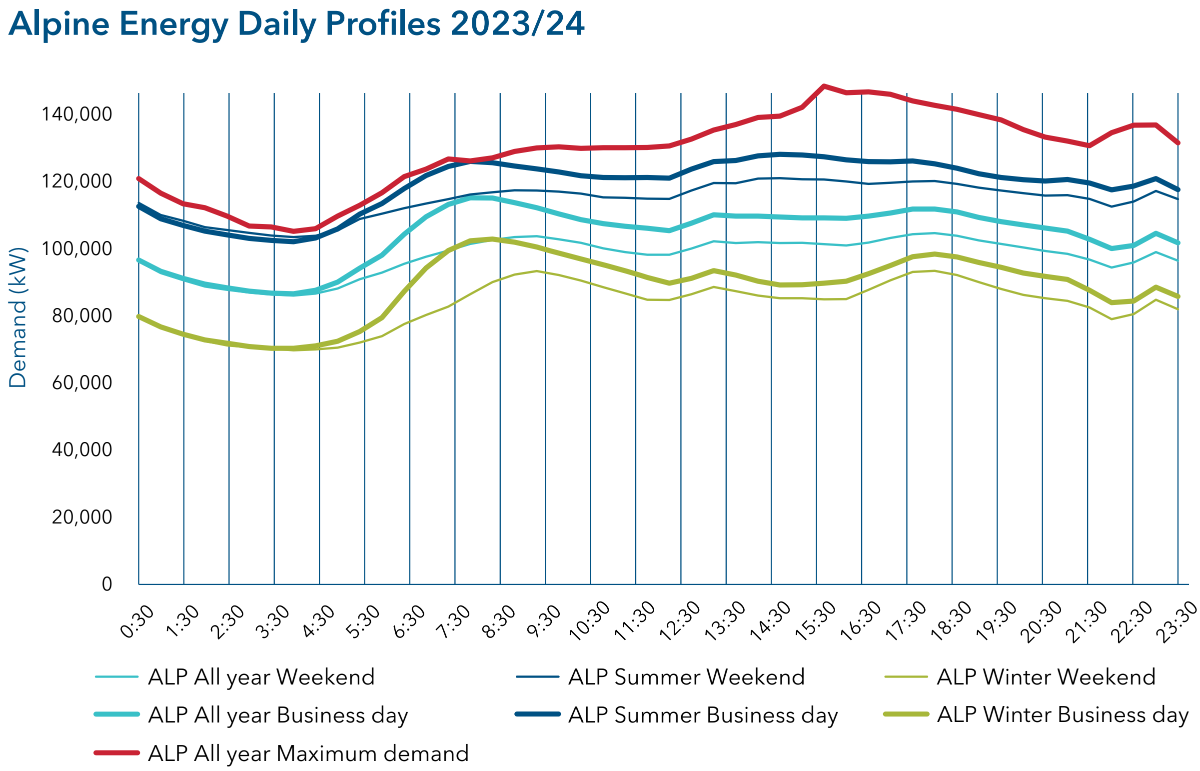


Figure 2: Seasonal daily profiles of the Alpine Load

Another defining characteristic of our network is the volatility of summer energy demand, driven by the high penetration of irrigation loads. Historical data illustrates this variability, as shown in Figure 3, which highlights the range of kWh delivered per month from 2014 to 2024. The greater variability during summer months is evident when compared to winter months.

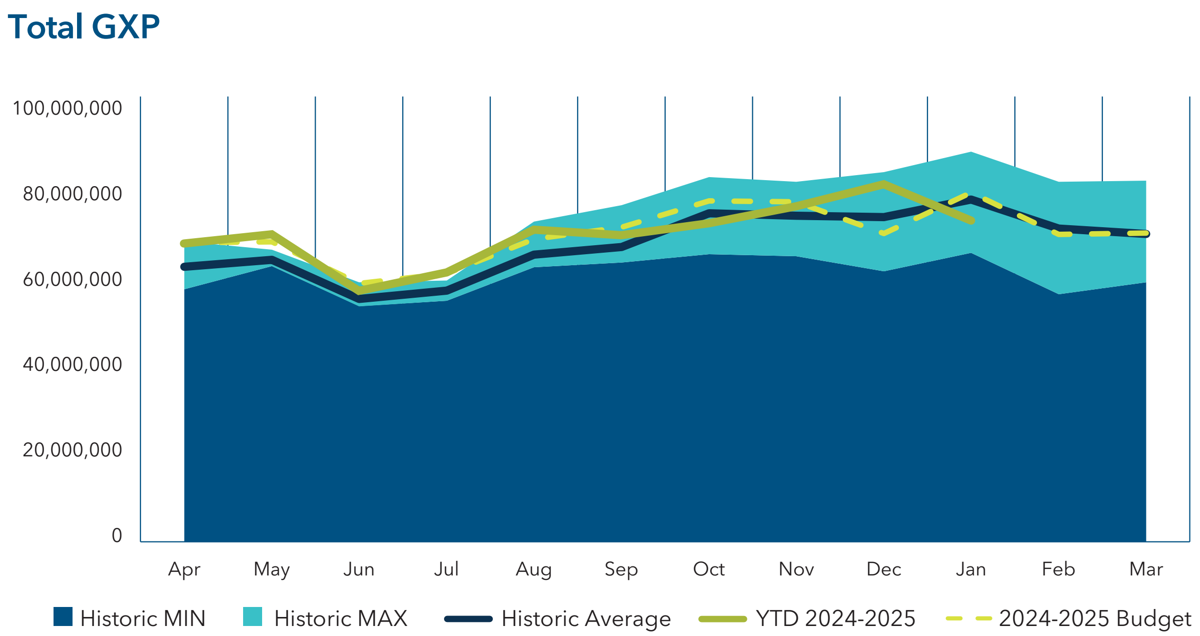
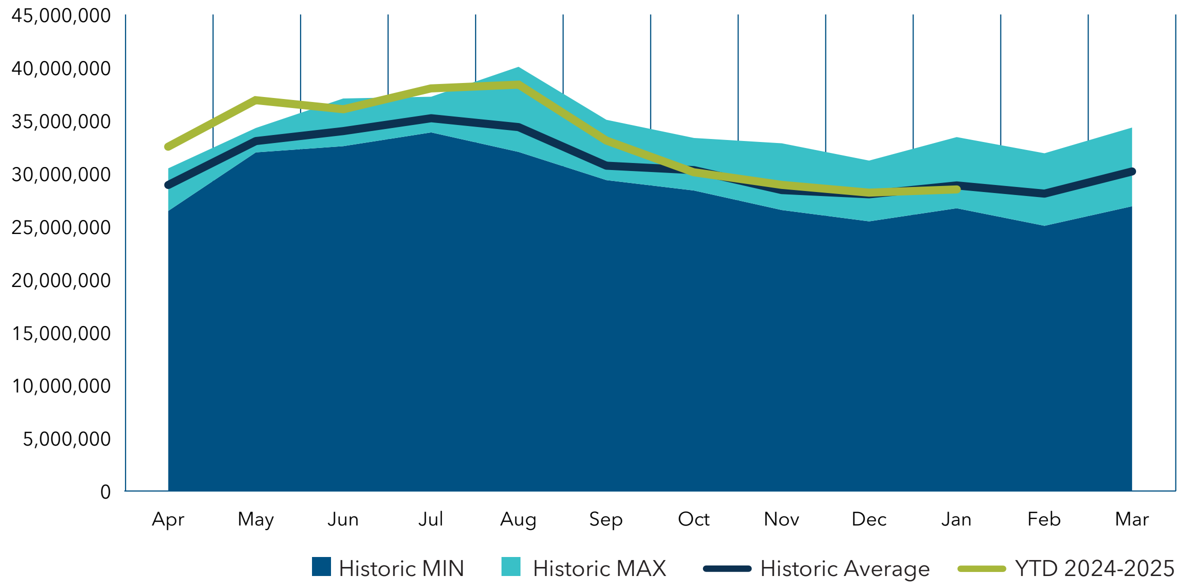


Figure 3: Relative Volatility of Summer Demand

During summer, maximum demand at Timaru GXP averages 25% higher than the minimum, whereas Bell's Pond GXP exhibits a much larger swing, with maximum demand 125% higher than the minimum. This significant volatility in irrigation supply volumes is illustrated in Figure 4.

Timaru



Bells Pond

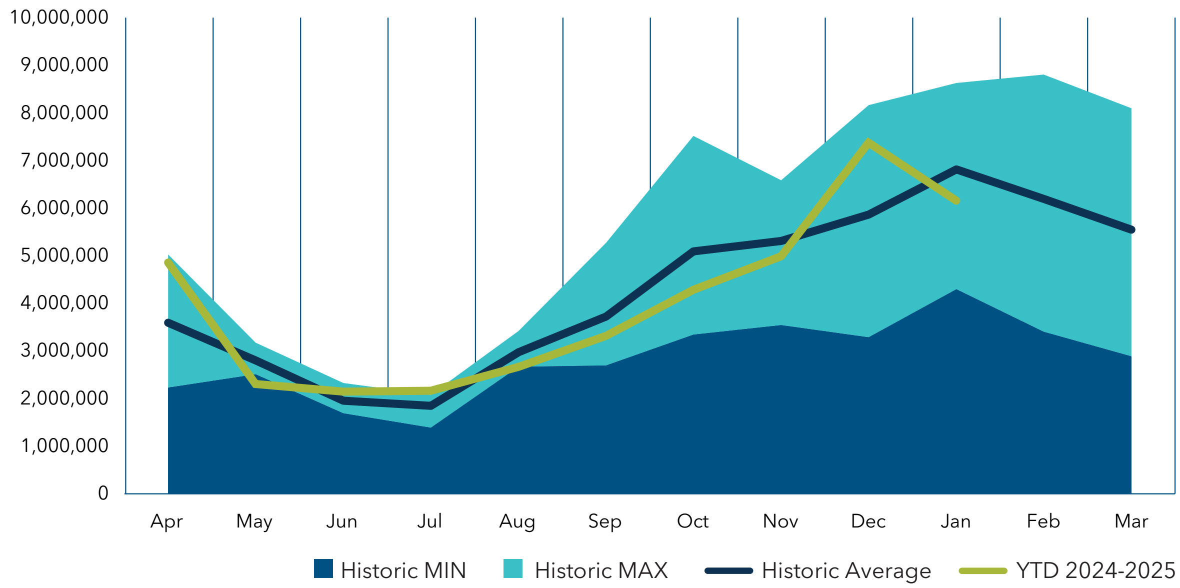


Figure 4: Volatility of Summer Demand for Irrigation

The inherent variability of irrigation demand poses challenges for accurately forecasting annual kWh volumes, which can lead to variances between budgeted and actual revenue. To address this, we have adopted a pricing methodology that emphasises capacity-based charges, helping to mitigate revenue risks associated with weather-dependent irrigation load fluctuations.

Lower variable charges, however, can result in reduced consumer responsiveness to price signals, including those based on day/night differentials in our pricing methodology, which are now minimal. This highlights the importance of ensuring that pricing reflects the cost of supply, particularly through capacity charges.

Encouraging consumers to adjust their capacity in response to system conditions can significantly impact long-term cost management and network performance. Section 3.5 below details our plan to investigate dynamic capacity pricing options to better manage our existing network constraints and respond to the forecast demand growth.

3. Pricing review and Roadmap

This section provides an overview of our pricing review of the Roadmap we have developed (refer to Appendix A).

In 2024 we commenced a review of our pricing approach. This initiative aligns closely with the EA's expectations for distribution pricing reform, detailed in a letter sent to all distributors in May 2024[1]. The EA underscored the critical role of distribution pricing reform in addressing both the challenges and opportunities arising from the increasing electrification of the economy. As electricity demand grows and distribution networks transform into bi-directional systems, the need for effective, forward-looking pricing mechanisms has become critical to support efficient investment and ensure long-term affordability for consumers.

The EA's letter emphasised that pricing reform is essential to managing the significant investment required in distribution networks while facilitating the adoption of electric vehicles, emerging technologies, and distributed generation. By prioritising the optimisation of network investment and the reduction of pricing distortions, the reform seeks to achieve better outcomes for consumers and advance New Zealand's goal of achieving net-zero carbon emissions by 2050.

In response, we are aligning our pricing review with the EA's expectations, ensuring that our methodologies are consistent with the changing needs of the electricity sector. This work focuses on developing pricing structures that accurately represent the costs of network use while delivering clear and effective signals to consumers.

By prioritising fairness, efficiency, and sustainability, we aim to support a more equitable and resilient electricity system. This alignment reflects our commitment to meeting regulatory requirements and delivering innovative, consumer-focused pricing solutions that facilitate New Zealand's transition to a low-carbon future.

We have identified seven priority actions to deliver on our strategic pricing objectives over the next five years:

1. Phase out of the Low Fixed Charges
2. New naming conventions
3. Introduce new tariffs to better align cost and network use
4. Equalise day/night variable charges
5. Research opportunities to enable (dynamic) time-of-use capacity pricing
6. Develop a consumer and retailer engagement plan
7. Develop a Connection Pricing Policy and implement a new Connection Pricing Methodology

We will review and report on progress against these actions and any outcomes annually as part of our Pricing Methodology review.

3.1 Phase out of the Low Fixed Charges

The gradual phase-out of the LFC Regulations represents an important step towards implementing more efficient and cost-reflective pricing. Established under the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, these rules required distributors to offer residential consumers a tariff option at their primary residence with a fixed daily charge capped at 60 cents (excluding GST) in 2024/25, up from the original 15 cents per day previously. This tariff also mandated that the combined annual fixed and variable charges for an average consumer using up to 9,000 kWh per year should align with comparable tariffs nationwide.

[1] Electricity Authority Te Mana Hiko (2024). *Open Letter to Distributors: Distribution Pricing Reform*. Wellington, New Zealand. Available at: https://www.ea.govt.nz/documents/4821/Distribution_Pricing_Reform_-_Next_steps.pdf

In September 2021, the government announced plans to eliminate the LFC Regulations over a five-year period acknowledging the unintended inequities that resulted from this policy. This decision was enacted through the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021, which came into force in November 2021. The amendments allow for an annual 15-cent increase in the fixed daily charge, with the regulations set to be fully repealed by 1 April 2027.

This phased removal has supported the transition to pricing structures that better reflect actual network costs. By enabling distributors to increase the fixed component of pricing, the reform has facilitated a more accurate recovery of costs, improved the ability to pass through transmission charges, and delivered stronger price signals to consumers.

As the transition progresses, low consuming residential consumers will experience higher fixed daily charges paired with lower variable rates. The variable charges for this group will align with those applied to other mass-market consumers, representing a reduction to approximately 15% of the current rates. Meanwhile, the fixed daily charges will correspond to either our standard 015 pricing category (approximately three times the final LFC fixed daily charges) or a proposed new pricing category offering a 32-amp single-phase supply (set out in section 3.3 below) with fixed daily charges set at roughly double the final LFC rates.

For the average LFC consumer, annual electricity costs are expected to remain relatively consistent when transitioning to the standard pricing categories. Consumers at the higher end of the LFC consumption spectrum (close to the maximum 9,000 kWh per year) will likely experience little to no change in yearly charges, while those with lower consumption may face increased costs unless they opt for the proposed 32-amp single-phase pricing plan, which is designed to keep annual charges comparable for low-use households.

This transition aims to balance the phase-out of LFC charges by ensuring minimal impact on other pricing categories, allowing for a smooth adjustment as we move towards the final phase.

3.2 New naming conventions

It would provide better clarity to consumers if pricing categories were named according to a simple and consistent convention. Consumer enquiries highlight that our naming conventions for different pricing categories are overly complex. For example, some consumers struggle to understand the difference between the 015 and the 360 pricing categories. The proposed change would reduce confusion around our naming conventions. This change will also allow for the efficient naming of any new pricing category that could be introduced to accommodate consumer requirements and alignment with naming conventions with other distributors.

3.3 Introduce new tariffs to better align cost and network use

3.3.1 Smaller capacity connection (targeting current LFC consumers) e.g. 8kW

The aim is to encourage low consumers to move to a standard, more cost-reflective pricing category during the phase-out of the LFC Regulations. Doing so will provide us with a smaller potential peak load to service, due to the smaller connection size limiting consumers' peak demand. Current calculations show that consumers on the LFC option will generally pay less if they switch to the new 8kW pricing category rather than staying on the LFC option as the phase-out of the LFC continues. This is because the cost benefits shift at specific consumption levels such as around 9,000 kWh per year for the standard 015 price category and at progressively lower usage levels for the 8kW category.

3.3.2 30kW tariff for large residential/small commercial consumers

Feedback from large residential and small commercial consumers has indicated that some of them are dissatisfied with the current pricing options. This feedback relates to the 045 (45kW) pricing category and the assessed (ASS) pricing category. Currently, the cost gap for consumers between the 015 and 045 pricing categories is large. Approximately 200 consumers have consumption that falls outside the limits of the 015 pricing category but well below the limits of the 045 pricing category (the next largest pricing category). In addition, the current 015 consumers with increasing demand would more easily consider a smaller increase in cost and capacity than the current jump to the 045 categories. A 30kW supply would help to alleviate these issues.

3.4 Equalise Day/Night variable charges

After our pricing methodology changed to the 80% fixed 20% variable revenue approach in 2023, the price differential between our night-time and day-time rates became immaterial (i.e. less than $0.01 per kWh lower) as a price signal.

The equalisation of day and night variable charges is not expected to have a significant impact on how retailers package pricing for consumers. In most cases, retailers include the distribution variable charge within the higher overall variable cost of energy from generators. Consumers with different retail day and night rates may observe a slight reduction in the day/night price differential on their retail invoices, estimated at around 5% to 10%. For consumers who have opted for a single variable rate for their energy, no change will occur.

It is important to note that the current day/night differential in distribution variable charges does not adjust based on actual demand patterns. For example, daytime charges remain higher even during periods of reduced demand, while night-time charges are lower even during near-peak demand periods. The growing adoption of electric vehicles could further shift these dynamics, potentially creating a new peak demand period around midnight due to widespread overnight charging.

Generator energy prices, being more dynamic, provide price signals closely aligned with actual demand. These signals will continue to influence consumption behaviour for consumers exposed to real-time pricing. On the distribution side, the proposed dynamic time-of-use capacity pricing, as discussed below, would enable real-time adjustments to demand, ensuring more efficient management of the distribution network during constrained periods.

As the variable charges are broadly consistent across all pricing categories, excluding the current LFC categories, the removal of the day/night differential will have a similar impact on all consumers. Even for current LFC consumers, the day/night differential is comparable to that of other pricing groups.

3.5 Research opportunities to enable (dynamic) time-of-use capacity pricing

We propose to explore options for implementing a dynamic time-of-use capacity pricing model, enabling consumers to select a lower-cost, controlled supply option.

An example of how this could work includes a system where our network control operators might reduce the connection capacity of participating consumers during specific, constrained periods, rather than applying restrictive pricing at fixed times of day. This dynamic pricing approach would deliver more accurate, cost-reflective pricing based on actual network constraints, encouraging demand flexibility only when necessary[2]. Consumers opting into this model might receive a reduced daily or demand charge in exchange for agreeing to adjust their consumption during constrained periods, helping manage load growth and potentially deferring capital investments.

[2] Night-time consumption is typically lower than daytime consumption since most people are asleep, and demand is less responsive to price changes during these hours. Actively managing demand, when necessary, would be more effective, enabling us to defer capital investment in supply capacity. This approach also supports electricity usage during unconstrained periods, avoiding unnecessary discouragement of consumption.

Conversely, those not participating could pay slightly higher rates to balance the revenue shift. Historically, ripple control on hot water cylinders effectively reduced peak demand charges from Transpower, but these charges were removed under the updated Transmission Pricing Methodology (TPM) from April 2023. This shift has made the traditional controlled versus uncontrolled pricing model less relevant, prompting us to consider alternative applications of remote switching technology, such as more effective congestion management.

Within the sector, there is ongoing work on future flexibility, which could impact the design and application of time-of-use pricing. We will closely monitor these developments to ensure our approach remains aligned with industry trends and best practices.

The market may also offer opportunities to manage congestion and optimise pricing. By exploring available market solutions, we can identify innovative ways to integrate flexibility and capacity management into our pricing model, potentially resulting in more efficient and sustainable outcomes for both consumers and the network.

Preliminary analysis indicates that several zone substations are approaching or exceeding capacity during winter peaks, highlighting the potential benefits of deferring system growth investments. As part of our pricing Roadmap, we propose to research technological and operational solutions, while modelling the impacts of dynamic time-of-use pricing over the next three years.

3.6 Develop consumer and retailer engagement plan to support our Pricing Strategy and Roadmap

We plan to tailor our messaging, educational resources, and interactive channels to reach both consumers and retailers. The aim is to ensure that our pricing messaging is clear, accessible, and aligned with our organisational strategy. This will consumers and retailers understand how the Pricing Strategy impacts them directly, promotes network efficiency, and delivers long-term benefits.

3.7 Develop a Connection Pricing Policy and implement a new Connection Pricing Methodology

This action reflects our focus on creating a new connection pricing policy. The EA's consultation on distribution connection pricing has concluded, and we will use the guidance from this process to inform the development and implementation of our new policy. This will be completed by 1 April 2026.

4. Progress against Roadmap

In 2025, we will publish our first Roadmap, detailing our pricing strategy for the next five years. Below are the stages of the Roadmap that will be implemented by 1 April 2025.

Workstream	Description	Timing
Continue to phase out LFC	Fixed prices increase from 45 cents to 60 cents for consumers on the low fixed charge	From 1 April 2025
Introduce a new pricing category	A new 030 (30 kW) price category would address the cost gap between the 015 and 045 categories, providing a better option for consumers with requirements too large for the 015 pricing category but too small for the 045 pricing category	From 1 April 2025
New naming conventions	Simplifying pricing category names to reflect connection capacity will enhance clarity for consumers and stakeholders. Proposed changes include replacing LOW with 008 (8kW) and renaming 360 to 045 (45kW) to align with capacity measurements	From 1 April 2025 & ongoing

Table 2: Roadmap implementation

5. Incorporating the Electricity Authority's pricing scorecard feedback

The Electricity Authority's 2023 Distribution Pricing Scorecard highlighted several areas where we can improve our approach to distribution pricing. In response, we prioritised the development of a pricing strategy and roadmap to address these areas and align with the Authority's principles.

Key areas for improvement include providing a more detailed analysis of future network congestion and its potential impact on pricing, developing clearer pricing signals to reflect network costs, and incorporating more quantitative information into our pricing framework. The feedback also emphasised the importance of establishing a structured roadmap to guide our pricing decisions over the long term and ensuring greater transparency in how we calculate subsidy-free ranges.

The 2023 scorecard results (Figure 5) show that Alpine Energy ranks near the bottom of the overall scores compared to other EDBs. This underscores the importance of strengthening our pricing approach to better align with the expectations set out by the EA.

Our pricing strategy and roadmap have been designed to address these gaps, focusing on aligning pricing with long-term network needs and improving transparency. This work incorporates detailed network congestion analysis, provides clearer cost-reflective pricing signals, and supports consumer engagement to ensure the strategy meets their needs.

By addressing these areas, we aim to align more closely with the EA's expectations, ensuring our pricing approach supports efficient investment, delivers fair outcomes for consumers, and maintains the long-term sustainability of the network.

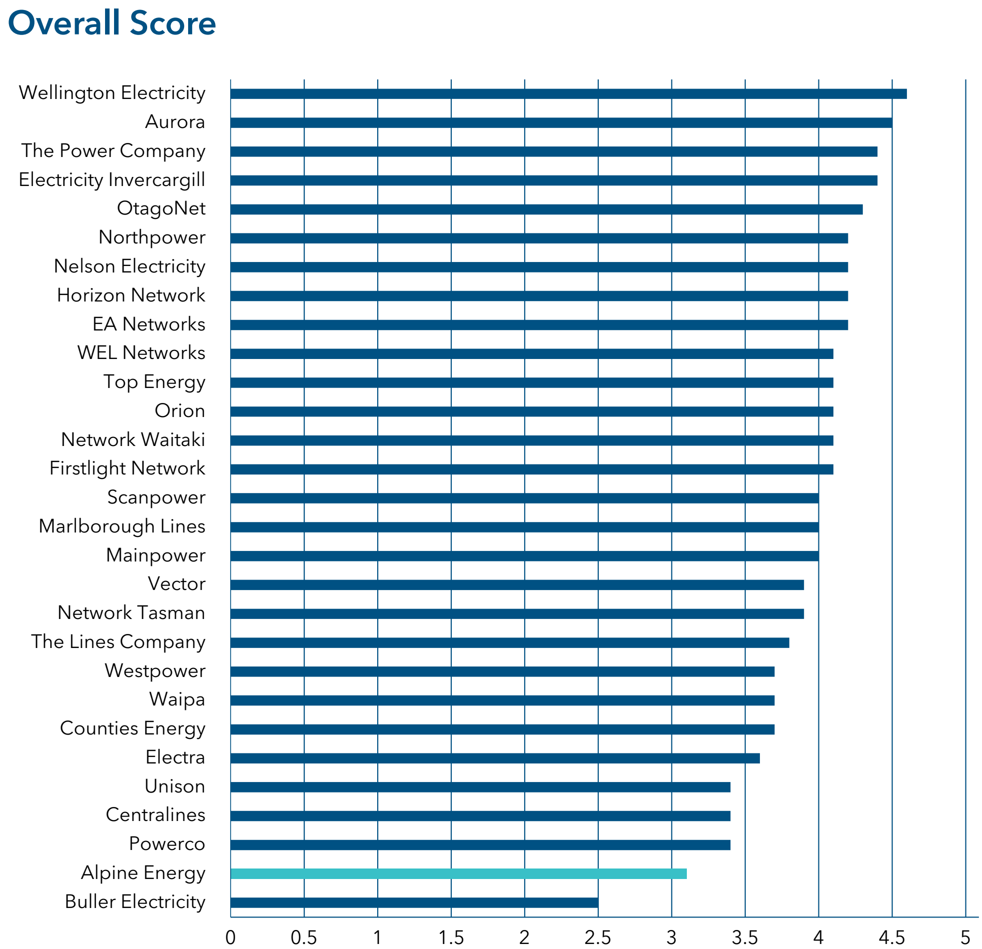


Figure 5: EDB overall scores for the 2023 Distribution Pricing Scorecards

6. Appendix A: Roadmap

	2024/25	2025/26	2026/27	2027/28	2028/29
Phase out LFC	Fixed prices move from 45c to 60c	Fixed prices move form 60c to 70c	Fixed prices move from 75c to 90c		
New naming convention	Introduce 045 pricing category (old 360)				
Introduce 030 pricing category (8kW, 32amp connection)	Research	Trial including customer feedback	Review and refine	Final implementation	
Introduce 030 pricing category: • 1x80amp • 2x60amp • 3x32amp	Implementation	Monitor, review and refine (if necessary)			
End daytime & nighttime variable charges	Decrease daytime and increase nighttime prices		Complete		
Alternative use of ripple control technology	Research and test switching technology to change between fuse sizes to enable TOU Capacity Pricing				
Smart meter capability	Research smart meter capabilities e.g. to do load selection and switching				
Dynamic time-of-use capacity pricing	Research costs and obstacles to implementation				
Consumer & retailer engagement plan	Continuous process - engage with customers and retailers on our pricing				
Develop a Connection Pricing Policy		Use the guidance from the EA's consultation on distribution connection pricing to complete our Connection Pricing Policy			

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