24 March 2026

Commerce Commission, Electricity Authority, and Energy Efficiency and Conservation Authority
c/o Electricity Authority
By email: distribution.feedback@ea.govt.nz

Tēnā koutou,

## Ensuring consumers benefit from efficient investment in non-network solutions

Powerco welcomes the opportunity to respond to the joint letter from the Commerce Commission (**Commission**), the Electricity Authority (**Authority**), and the Energy Efficiency and Conservation Authority (**EECA**) about the use of non-network solutions (**NNS**).

Powerco agrees that electricity distribution businesses (**EDBs**) must maximise opportunities to use flexibility services and flexible connections or other non-network solutions to provide improved outcomes for customers, where prudent and efficient. Delivering a least-cost and secure transition to a low-carbon economy will require efficient participation of various forms of non-network solutions alongside traditional investment. There is a risk however, that well-intentioned but premature policy and regulation could undermine this transition. The focus must be on the most efficient solutions to meet customers' needs, rather than prescriptive regulation directing solutions.

In this response, we suggest how the agencies can support EDBs efficient and innovative use of non-network solutions without limiting market development, or efficient use of traditional solutions, and we offer practical examples demonstrating that integrating these solutions is highly achievable for EDBs. We provide comment in the attachment to this letter on our approaches, experiences and suggestions. Our summary observations are:

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| **A layered, market-based, approach is best** | • Powerco’s approach to flexibility services involves layering cost-reflective pricing with alternative product options<br>• This empowers third-party retailers and flexibility providers to build portfolios of resources to efficiently respond to price signals or contractual incentives, rather than being forced into mandated pathways. |
| **Regulation must enable market efficiency** | • There is opportunity through the next price-quality reset and the current pricing reforms to ensure the settings are fit for a future where NNS may need to be treated differently. For example, different categories of opex with different treatment and incentives to enable increased integration of NNS into existing processes.<br>• Incentivising all EDBs to accelerate the use of NNS will drive efficient solutions. Forcing uptake or standardisation comes at the cost of innovation, and we need to be careful not to stifle innovation through regulation.<br>• Regulation should not prescribe outcomes or technology as  we cannot predict what technologies or customer preferences the future will bring. Well-intentioned but |

premature regulatory policies prescribing technologies (like home energy management systems), risk non-optimal solutions and loading unnecessary costs onto consumers.

| | |
|---|---|
| **Implementing non-network solutions is achievable now** | • Powerco's active case studies demonstrate that integrating flexibility is not prohibitively difficult. However, it does require EDB capability and commitment. Other non-network tools are also being effectively applied to optimise network investments, for example through network visibility<br>• Using robust evaluation tools, establishing market platforms, running targeted trials and developing pricing options, proves that EDBs can confidently deploy non-network solutions today. |

We are always keen to meet with the Commission, the Authority, and EECA to discuss our ideas further. If you have any questions or would like to talk further on the points we have raised, please contact Emma Wilson

[redacted]

Nāku noa, nā,

[redacted]

**Emma Wilson**
Head of Policy, Regulation and Markets
**POWERCO**

# Non-network solutions are one of the most effective ways of responding to the energy trilemma

Powerco is putting significant effort and investment into becoming a network of the future to meet the evolving needs and services our customers want.

The Trilemma has shifted away from sustainability, with security and affordability currently dominating. While it will change again, the affordability focus will endure. Forecast electrification growth hasn't 'kicked off' as we expected, which has only amplified affordability challenges.

We believe smarter distributor capability and NNS is one of the most effective ways of responding to the energy trilemma in order to:

- Reduce energy costs to our communities
- Enable rapid customer decarbonisation; customers to become an integral party of the energy solution and monetizing those services
- Help maintain network stability.

While NNS is about embracing new ways of doing things, it's also about evolving the way we use traditional EDB services (eg price signals and commercial arrangements). The range of solutions available will not only allow us to defer or avoid network upgrades but will also minimise cost to consumers where there is a need for network investment.

The outcome should be to provide the best result for consumers, which may be to minimise costs now, shift costs to another period or improve reliability.

We recommend that the regulators align and clarify terminology around NNS. For the purpose of this response, we have focused on flexibility services and flexible connections as this appears to be the primary interest of your letter.

In addition to the above, it's important that equity is considered. Industry surveys show that those of higher financial means are likely to have a much greater ability to flex their load or generation (EVs, Solar, Batteries). For customers in energy hardship, care is required to ensure their energy is affordable and only appropriate consumer responses are instigated, such as hot water control rather than heating control.

Managing energy affordability for individual consumers is important in the context of accelerating NNS. For example, more cost reflective pricing may increase energy hardship for areas such as rural communities, who currently experience lower prices due to price smoothing.

We would like to better understand how all EDBs can support equity and hardship in ensuring all consumers benefit from more use of NNS.

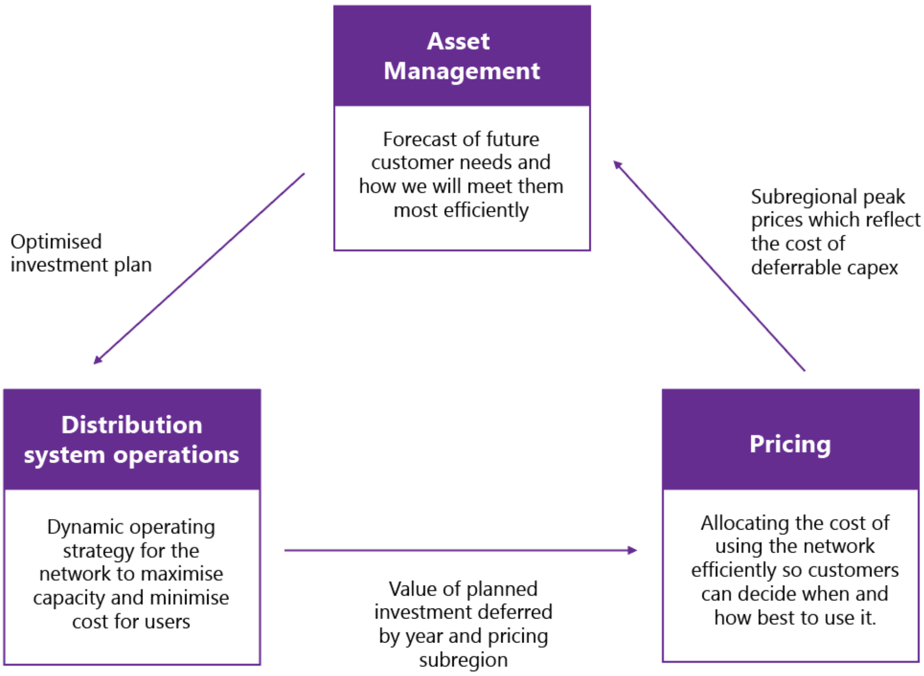
## 1. Powerco has a layered approach to pricing and flexibility

Powerco's approach focuses on layering cost-reflective pricing with firm and non-firm flexibility products for those who choose to participate.

### The framework for flexibility and pricing

Our flexibility services framework aligns our pricing roadmap with our Asset Management Plan (**AMP**). Where the AMP identifies investment is required in the next 5 to 10 years, we are working towards being able to signal the cost of these planned investments using location-specific peak pricing[1]. Where investment is needed within 5 years, we initiate location-specific, multi-year flexibility tenders with third parties. The relationship between pricing, asset management and flexibility options where the AMP identifies a forecast investment, is illustrated in Figure 1.

Figure 1 Relationship between pricing, asset management and flexibility where the AMP identifies investment need




Flex and price signals are not always directly linked to documented (in the AMP) investment plans. Flex and price signals are tools that can be used before investment need is identified. In some cases, once investment need has been identified, it is too late to manage constraint through flexibility services or pricing. On the other hand, there could be a lot of congestion (constraints) that do not yet, and never will, justify investment; but still would benefit from flex. With early flex engagement, constraints (and need for network investment) may be avoided, even before the need for investment is identified, especially if growth is low.

During the past year, we have introduced targeted pricing initiatives, such as the Coromandel sub-region pricing, which allows us to test local peak signals in an area with pronounced seasonal demand. Export rebates were

[1] Location specific pricing is not operational in the current regulatory year but will increasingly be used in the years ahead.

implemented in FY26 to reward local generation that helps offset demand during congested periods, supporting participation from consumer energy resources (**CER**) where it is most valuable. [2]

We are assessing options for more tailored price categories and demand-based charges, particularly for larger connections and commercial customers. These changes are designed to provide clearer signals to customers, encourage demand response, and ensure costs are allocated fairly.

We review our pricing approach annually to check how pricing is contributing to demand response, peak timing and peak demand. Assessing the link between pricing and customer response to adjust future pricing structures will be more measurable once the low user fixed charge is no longer in place.

### A number of tools and inputs are required for flexibility initiatives

To support this dynamic demand management and identify where constraint could be managed or investment could be deferred, we need a demand forecasting model that is much more responsive to real-time changes in input factors compared to traditional models and can reflect the impacts on a much more granular scale. Demand forecasts are a key input into network planning, and their veracity is therefore very important for optimal network investment. A new demand forecasting model is a significant commitment, and we are currently in investigation and testing phase to determine the best product for Powerco.

During 2025, we made substantial progress in improving visibility across our low-voltage (**LV**) network. The deployment of Gridsight, our new LV analytics platform, and ongoing development of a comprehensive LV network model will allow improved LV network management, faster response to LV outages, and advance identification and avoidance of LV network constraints. Combining this improved network understanding with the capacity for flexibility services will allow us to optimise utilisation of this network, potentially deferring significant under-utilised investment.

We are investing in further network modelling, customer research, and our data and digital foundations, which underpin our ability to operate a more flexible, data-driven network.

We are also building the tools to be able to compute localised price signals based on forecast congestion, with the aim to put localised price options into the retail market.

### Complementary initiatives are planned over different time horizons

The falling cost and improving capability of new technologies for both us and our customers to control demand and store or generate electricity means that the opportunity to do this economically is improving all the time. Over the next decade we will refine and align our complementary flexibility initiatives with efficient probabilistic planning to optimize network and non-network investment. Complementary initiatives are linked to different time horizons as illustrated in Figure 2.

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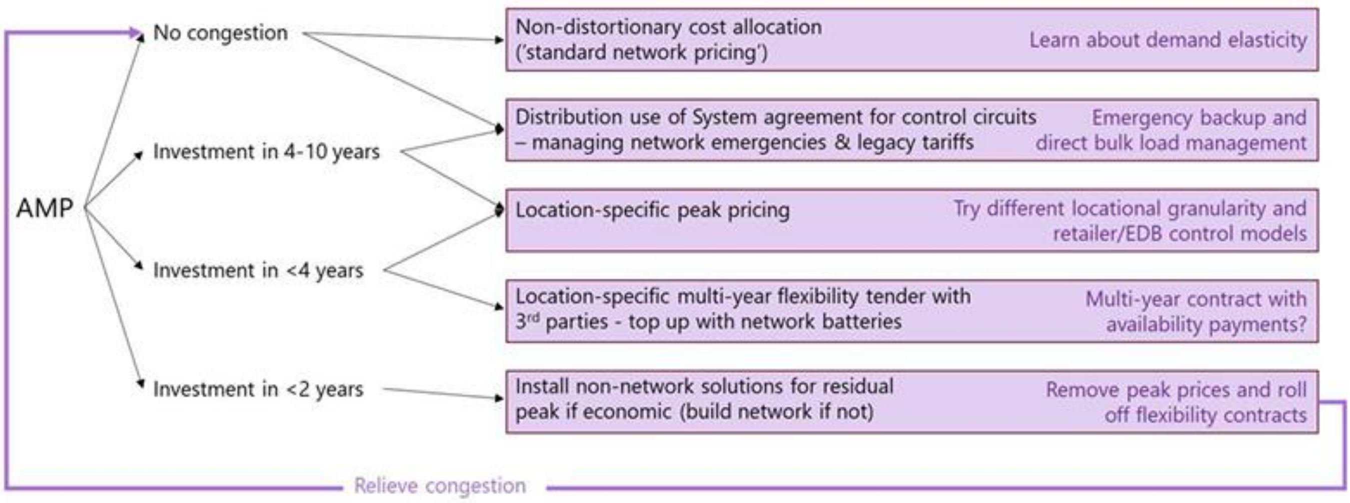
[2] Powerco pricing methodology: Powerco 2026 Electricity Pricing Methodology

Figure 2 Powerco AMP investment - flexibility time horizons




To operationalise this, we are structuring flexibility into three distinct network assistance rate products to address localised constraints with spatial and temporal granularity:

- Scheduled: Habitual/daily response via tariffs
- Forecast events: Response called 10-35 times a year during high peaks
- Contingent events: Rare contingent/emergency response

By providing clear price signals and distinct products, we want to empower third-party retailers and flexibility providers to build portfolios of resources to respond in whatever technological configuration is most efficient. This dynamic pricing approach may not be able to be accommodated in the current settings for annual price setting, which is a once-per-year tariff setting process.

While Powerco's intent with flexibility services is to generally enlist third-party providers, there will be instances where we may have to directly control end-devices, for example in areas where interest from third parties to provide flexibility services is limited. We are developing operational processes for both direct management of DER and for dispatching flexibility services. In practice, mass market flexibility management will likely be coordinated via intermediaries, such as retailers or aggregators.

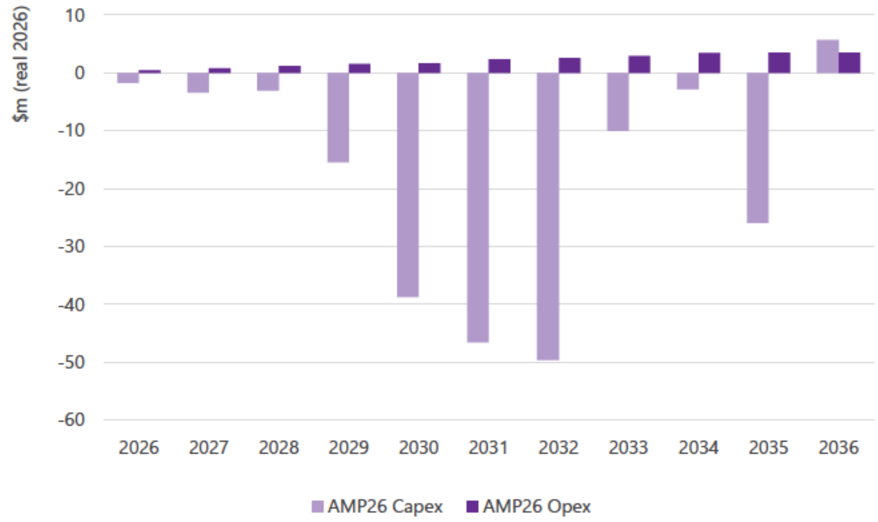
For example, with Localflex, we're working to a future where constraint information and flexibility offers will be shared on a very regular (days or weeks) basis, looking for support in the week-ahead, or even shorter space. This is similar to the Epex and Piclo platforms being used in the UK.

## Capex deferral is potentially significant

Based on our first tranche of identified flexibility projects, the comparison of deferment value with the (indicative[3]) cost of flex procurement is illustrated in Figure 3. This identifies a capex deferment potential of almost $200m over 10 years and the indicative cost of flex procurement as a guide to the scale of investment efficiency that implementing distribution system operator (**DSO**) capability can release.

[3] Final offers are still being developed.

Figure 3 Forecast capex deferred through flexibility and associated opex cost of flexibility procurement




## 2. Government agencies can actively accelerate the uptake of non-network solutions

We encourage the Commission, the Authority and EECA to review work programmes and give higher priority to initiatives to not only support NNS, but to support efficient use of the best solution for an identified need.

To ensure consumers benefit from efficient investment, we must rely on market-based processes rather than prescribing outcomes or technologies. There is a tendency to jump to specific technology solutions for transition affordability, despite it not being clear of the best solution. For example, while it is necessary to thoroughly test and evaluate end-use technology such as home energy management systems (**HEMS**), prematurely regulating a solution risks missing a potential better solution[4]. It also risks running contrary to the October 2024 Government Policy Statement on Electricity, which emphasises competition and explicitly states that "the rules of the market do not favour one technology or solution over any other".

History provides a clear lesson on the dangers of regulatory technology mandates. In 2009, the Parliamentary Commissioner for the Environment (**PCE**) recommended that smart meters be mandated to include Home Area Network capabilities, specifically favouring the Zigbee wireless communications profile. The Electricity Commission rejected this mandate in their 2009 paper, "Advanced Metering Infrastructure in New Zealand: Roll-out and Requirements" as the technologies were rapidly evolving. The Commission's restraint was supported by NZIER's independent cost-benefit analysis, which highlighted the severe risk of the mandated technology "becoming obsolete before smart appliances are introduced, incurring additional costs to replace with the new technology". Today, Zigbee is not a widely used protocol and material costs have been saved which would have been loaded onto consumers unnecessarily.

The Authority, EECA and the Commission must apply this exact same regulatory restraint today as there are many new products in development that will be needed to support non-network solutions. This will range from products

[4] For example, EECA has identified HEMS, heat pumps, and hot water systems and EV chargers as "priority products" for new standards. The proposal is for minimum voluntary specifications in 2026, which may eventually lead to mandatory regulations. https://www.eeca.govt.nz/regulations/equipment-energy-efficiency/about-the-e3-programme/

for EDB forecasting, investment evaluation, sharing information, aggregating demand, or managing consumer interface. EDBs and the market must be allowed to discover the most efficient flexibility solutions without being forced down mandated technological pathways.

We have made several suggestions throughout this response where the Authority, EECA and the Commission could support investment in NNS either through adjustments to regulatory settings, transparency measures, or by not regulating to ensure the market delivers.

## 3. A regulatory framework that delivers efficiency and innovation for all consumers

### Creating the right incentives through price-quality settings

Incentivising all EDBs to accelerate the use of NNS will drive efficient solutions and works best when parties see the tangible value and benefits in participating. When new approaches are voluntary and incentivised, EDBs are more likely to innovate, collaborate and share learnings. When it's forced through regulation, behaviour becomes compliance-driven and opportunities for genuine partnership diminish. Standardisation comes at the cost of innovation, and we need to be careful not to stifle innovation through these measures.

For all customers in New Zealand to see the same benefits will require sophisticated new DSO and other NNS capabilities, at each EDB. It is essential that no customers are underserved or have to pay too much for their energy. Consistent price-quality regulation for all EDBs, with appropriate incentives, will create the safeguards to ensure this. If the regulatory settings do not support investment in capability and capacity adequately and consistently, it creates a real risk of postcode differences in electricity services, quality and affordability.

Regulation that targets optimal performance across the full sector, will be most effective for the energy transition. It will not be as effective if only a sub-set of EDBs have the regulatory incentive. DPP5 regulatory settings are critical to ensuring the right incentives exist for EDBs to deliver the electricity services that customers want in the future. Many efficiency opportunities can be delivered via flexibility arrangements that defer (or replace) capital expenditure and incentives for EDBs to actively pursue such efficiencies should be a priority.

The current regulatory regime doesn't reflect the key role opex has in delivering non-network solutions and does not adequately incentivise EDBs to discover or pursue higher-risk opportunities to defer or replace capex with opex. The characteristics of capex and opex differ, as a traditional capital solution is generally lower risk, better known solution and doesn't involve new untried systems or process, compared with an NNS. That additional risk is not accounted for at scale in the regime, outside of the INTSA mechanism.

As we have mentioned in previous submissions,[5] DPP4 is all about trialling and gathering evidence to support optimal DPP5 settings. As we trial various NNS, we are learning and understanding quirks of the regulatory regimes we operate in which potentially create barriers to being able to roll out NNS at scale. It may be that regulators need to nudge EDBs (either through incentives or further scrutiny of investment decisions) to identify and pursue NNS, at least in the short-term until these become integrated parts of business-as-usual. This could include targeted incentive mechanisms that reward EDBs for future investment in NNS such as:

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[5] Powerco, response to Commerce Commission DPP5 open letter, 07 October 2025.

- A mechanism to reward the risk premium on opex solutions
- Opex expenditure on NNS is treated differently and excluded from the incremental rolling incentives scheme (**IRIS**)
- Mechanisms similar to INTSA / reopener for additional NNS allowance
- Removing barriers in the regime for funding or payments for flex services eg exclude from regulated income or treat as negative revenue.

An altered approach to SAIDI/SAIFI may also be required to recognise the consumer's ability to opt in to flexibility initiatives, and/or more granular level of reliability expectations and related penalties. For example, there is a growing number of consumers managing their own resilience when there is an outage.

### Different categories of opex need different treatment and incentives

The low-cost Default Price-quality Path (**DPP**) regulatory regime under Part 4 has served the sector well through a period that was stable and predictable. Decarbonisation through electrification is likely to see substantial growth in both supply and demand on distribution networks but with unpredictable timing. With a methodology and framework based on the principle that the historical operating environment is a good predictor of the future it's evident that regulatory settings do not currently support or incentivise EDBs to pursue NNS.

Despite changes in DPP4 allowing for greater scope of reopeners and opex step changes, there are fundamental issues with how opex is determined and treated throughout the regulatory period, that must be addressed.

We have previously questioned the suitability of maintaining the base-step-trend (**BST**) approach to forecasting future opex requirements.[6] Evidence is growing that treating all opex equally does not support an operating environment shifting to a heavier reliance on opex which is for different purposes compared to historically. The BST can only be relied on for recurring and predictive opex (base opex), which NNS opex is not, at least not until the market is mature. For example, NNS can be temporary in nature while capex investment is deferred, then when the capex investment is made in the future the NNS opex is no longer needed. This suggests that NNS expenditure requires a different treatment, both in terms of determining the expenditure requirements and also the incentives applied, compared to base opex. For example, base opex could retain IRIS and BST, meanwhile NNS opex should be excluded from IRIS and forecasted differently or set with a propose/approve model.

Larger flexibility solutions do not fit well within a 5-year regulatory window, and there is a timing issue whereby you need to start spending opex in one period (to build sufficient flexibility capacity), to defer capex that is planned for the following period. This has implications for the IRIS which only deals with capex/opex substitution within a regulatory period. While the equivalence of IRIS retention rates means that EDBs aren't penalised for substituting one for the other within period, they are also not incentivised if they do. EDBs are not incentivised to seek out opportunities to substitute capex for opex in the same way that the incentive exists to reduce costs, in order to retain profits across the regulatory period.
Similar to this, we are also seeing unintended consequences when using INTSA, due to the timing difference of when we spend the opex (current year) compared to when we receive the recoverable cost (the following year), whereby we receive an opex IRIS penalty for using the INTSA when we are spending to opex allowances in the

[6] Powerco, response to Commerce Commission DPP4 Draft decision, 12 July 2024, page 11.

current year, which may deter the use of the INTSA. This is not so much of an issue for smaller INTSA projects, but for Powerco who has ~$20million available, some INTSA applications could be significant. This is further evidence for why INTSA should be excluded from IRIS.

## Regulatory financial treatment of NNS

The context and activities in NNS are changing quickly and the payments EDBs receive and expenditure incurred to explore these opportunities are different to what we had historically. A number of unintended outcomes are baked into outdated legislation, determinations or the Input Methodologies (**IM**s). A more streamlined process for amending IMs or DPP determinations to account for changes may be warranted. For example, similar to the scope the Authority has to amend the Code in certain circumstances through a streamlined process.

An example where the IMs are out of step for NNS is that if an agency provides funding for NNS initiatives, trials or research, this is not revenue in the traditional sense, but it is currently unclear if this is accounted for as "other regulated income". This creates a disincentive to pursue these solutions if regulated revenues are reduced by these payments. This could be improved if payments like this to EDBs were excluded from regulated income and that funding offset the related opex, which is consistent with how funding related to capital works is treated.

## Pricing as an enabler

Alongside the opportunity to create the right incentives through the next price-quality reset, the Authority's pricing reforms are an important opportunity to optimize the important pricing lever available to distributors to support a future with more consumer control.

However, there are practical limitations on how much can be achieved in the short term. The Authority's decision on distributors' rebate for consumer supply at peak times[7] outlines three key changes to its initial proposal which recognise that:

- Price-based flexibility and contracted flexibility serve different purposes
- Distribution pricing is not well suited to targeted constraint management
- Highly granular injection pricing would be unworkable at this stage.

This is a pragmatic acknowledgement of the current state of cost-reflective distribution pricing and highlights the challenges that moving towards dynamic pricing would also come up against. Prescribed rules around frequency and process for notifying price changes do not support dynamic pricing and will need to be resolved to enable price-based flexibility.

Opt-in localised flex options (eg alternative "products in an area") is a way to maximise engagement and sends important investment signals for EDBs. For example, if a customer chooses to not opt-in, they are signalling that if required, they prefer a network side investment.

The incentives for EDBs to deliver consumer outcomes need to be clear to enable EDBs to work towards the desired level of pricing maturity in an efficient manner, rather than reactively.

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[7] Electricity Authority, Requiring distributors to pay a rebate when consumers supply electricity at peak times - Decision paper, July 2025.

# Case studies of Powerco's pursuit of non-network solutions

This consultation presents an opportunity to highlight the practical work EDBs are already doing. We want to demonstrate that integrating non-network solutions is not overly difficult; the tools and models exist today. We provide a number of case studies of Powerco initiatives in this section.

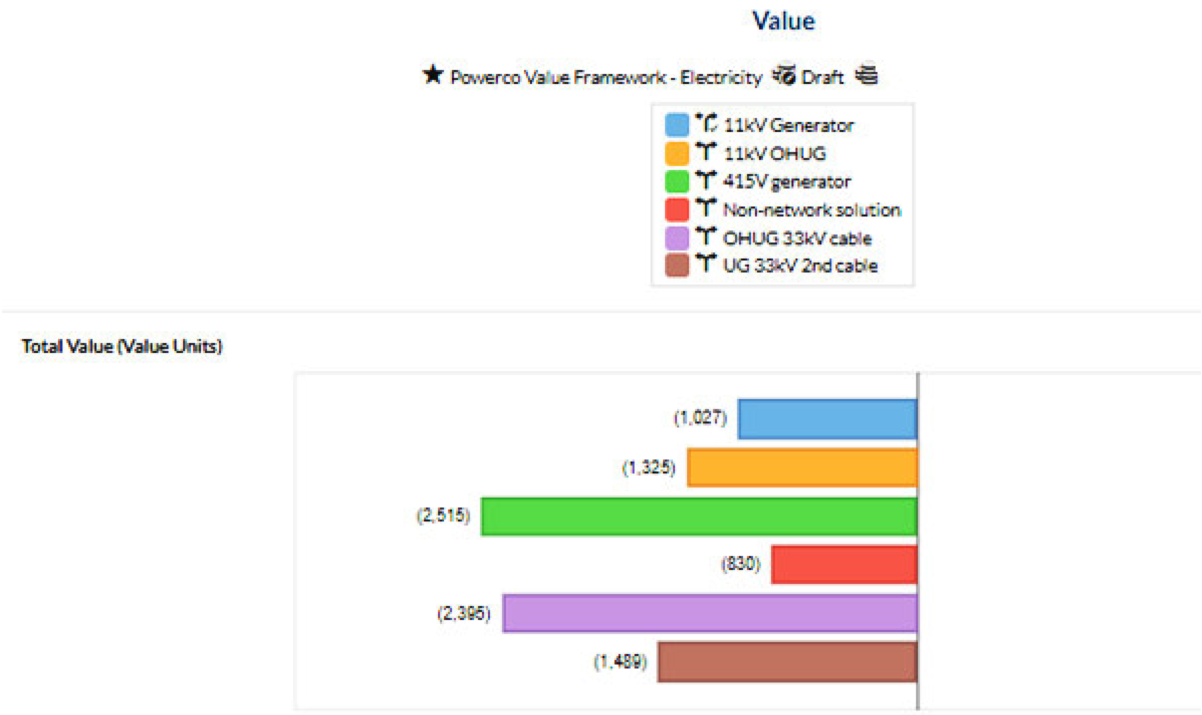
## Quantitative evaluation using Copperleaf

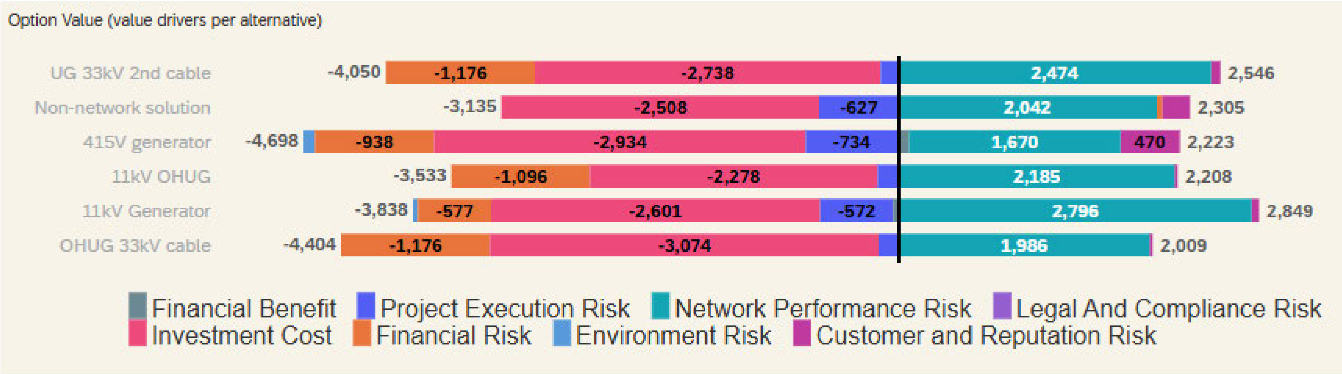
To assess and compare options, Powerco uses the Copperleaf asset management tool to identify and directly test least-cost traditional network solutions and non-network alternatives. Quantitative lifecycle modelling is performed and recorded in Copperleaf, which values:

- Capex investment costs
- Ongoing opex costs (maintenance, fuel and non-network support costs)
- Reliability benefits
- Electrical losses
- Unplanned SAIDI/SAIFI
- Project execution risk
- Customer and reputation risk
- Carbon emissions (from Powerco Capex investments only).

Figure **4** illustrates summary results from a Copperleaf evaluation of options in a recent project assessment. In this example, a number of traditional, back-up and non-network options where evaluated. The third-party non-network option has a lower cost. The differences in cost/benefit between the third party and Powerco options are due to the different costs, risks and benefits of the different options, as illustrated in the breakdown in Figure 4.

Figure 4 Copperleaf example






While there are some limits in the Copperleaf tool comparing absolute value of substantially different investment types, it is proved to provide an efficient and rigorous tool in comparing solutions.

## Powerco's experience with flexibility tenders

Where the asset management plan identifies the need for a planned upgrade within 5 years, there may be an opportunity to defer the project by paying third parties to inject electricity from a local generator or a battery or reduce demand in the affected area – using controllable load or injection in this way is called "turn-down flexibility". Conversely, we may incentivise consumers to increase electricity demand at times of excess distributed generation on a network ("turn-up flexibility").

Our first venture in this process was in 2018 when we called for expressions of interest in providing non-transmission network solutions as options for reinforcing electricity supply in the South Waikato. We received several imaginative offers that proposed using dispatchable demand, new and existing generation and batteries as an alternative to Transpower building a new network connection to support our customers. In this case none of the non-network alternatives were economically feasible but the process taught us a lot about the potential for using tenders of this sort to defer or avoid large, irreversible network investments.

In 2021 we ran a tendering process for network support to the Coromandel Region. Several flexibility providers offered us a range of non-network solution options with different costs and capabilities. Based on the costs and benefits of these options relative to a traditional network solution (reconductoring the Kopu-Tairua overhead line) and us investing in diesel generation at Whitianga, we awarded a contract to SolarZero in December 2022 to provide 1MW of network support in the north Coromandel during peak consumption times. The number of batteries in the region has increased over the last two years as more solar solutions are installed. While we have suspended the contract as a result of SolarZero's liquidation[8], the tendering process in 2021-22 taught us a lot about identifying flexibility options and using competitive processes to select the most efficient.

In September 2023, we livened four controllable fast chargers for electric vehicles at Z's forecourt in Waiouru. This pilot uses silicon carbide fast chargers from Kwetta (formerly Red Phase) which support the electricity network by intelligently responding (reducing load) to minimise impact during peak demand periods. It can even provide network support during high load periods. Early results from the pilot suggest that this type of technology will allow more EV fast charging infrastructure to be installed on our existing electricity network, without the need for

[8] SolarZero enters liquidation | RNZ

major capacity upgrades to support extra load. In December 2023, Z Energy livened [a 500kW flexible Kwetta EV fast charging array at Ngātea](), on a part of our network which has voltage constraints during peak periods.

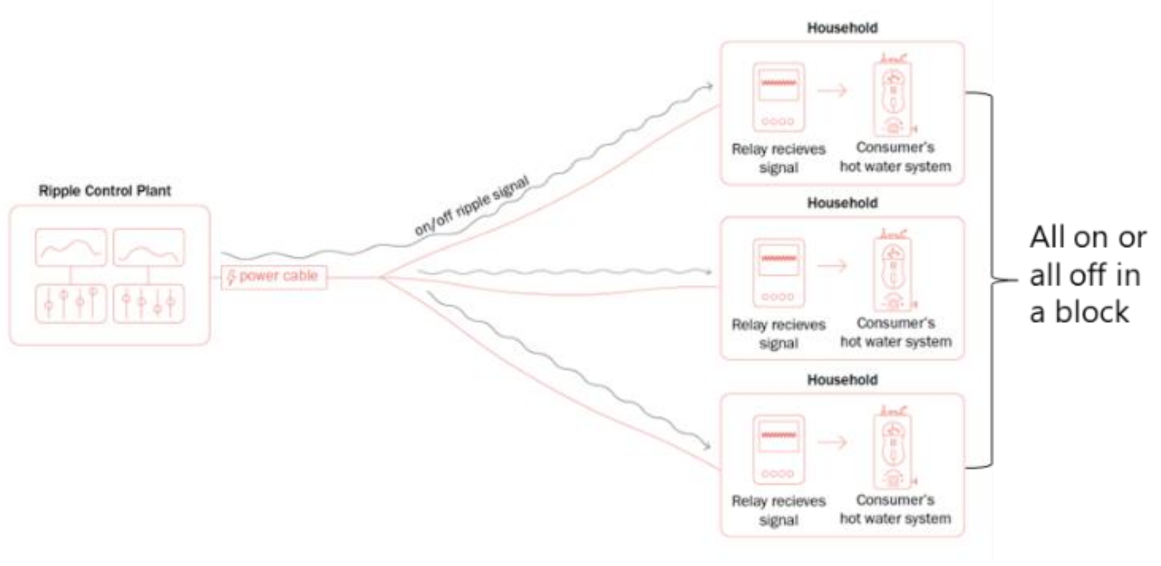
To avoid the cost of network upgrades, the EV fast charger deployed includes grid support functions, including Static Synchronous Compensator (“STATCOM”) voltage support and harmonic cancelation functions to effectively unlock grid capacity. The STATCOM functionality allows the EV charger to support the grid voltage during charging. When not charging, the STATCOM supports Ngātea’s voltage during constrained periods. These features allowed the charger to be deployed in less than three months as an interim solution until a longer-term network option is implemented. Again, this project has informed our understanding of how we can use flexible connections to minimise the cost and maximise the speed of the transition.

Our trials with Kwetta and Z have allowed us to learn about “dynamic operating envelopes” – where we allow customers access to constrained parts of our network on terms which make the most of network capacity when it is available but don’t adversely affect other network users when it’s constrained.

## Retailer load control trials at Powerco

Like all EDBs in New Zealand, Powerco offers “controlled” tariffs to customers whose hot water cylinders (and certain other loads) are attached to a dedicated circuit which allows us to turn on and off (within limits). This technology has traditionally been valuable as a way of reducing load during local and national system emergencies for decades. It is a broad-based solution – we send signals along our power lines to switch all the hot water cylinders in the same part of the network on and off together, as illustrated in Figure 5 .

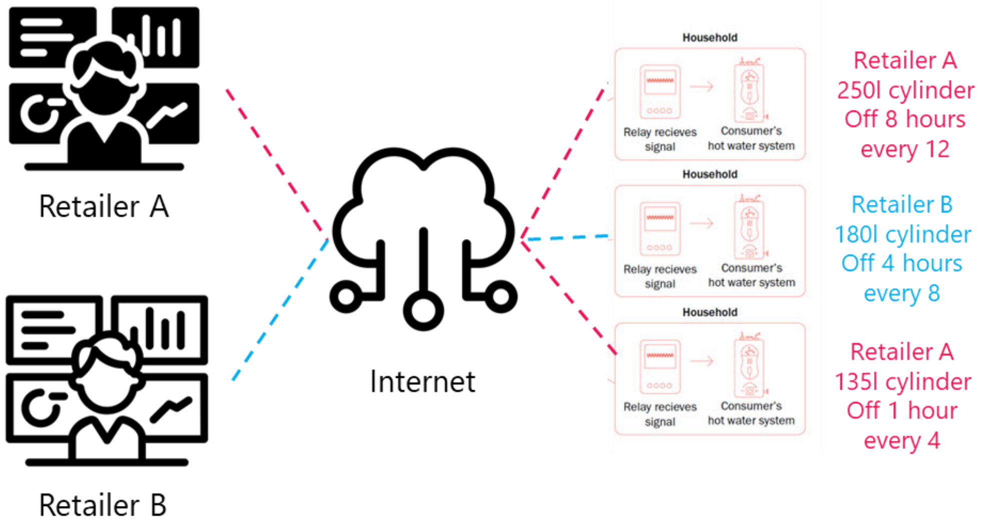
Figure 5 Traditional EDB ripple control[9]




With smart electricity meters sending information over the internet, the opportunity for granular control emerges – each connection can be switched on and off at different times, by different parties. This means that competing retailers can agree different operational protocols with each customer, depending on the size of their hot water cylinder, how much hot water they need and when they need it (refer Figure 6).

[9] Graphic credit *Ripple Control of Hot Water in New Zealand,* Power Systems Consultants for EECA, September 2020

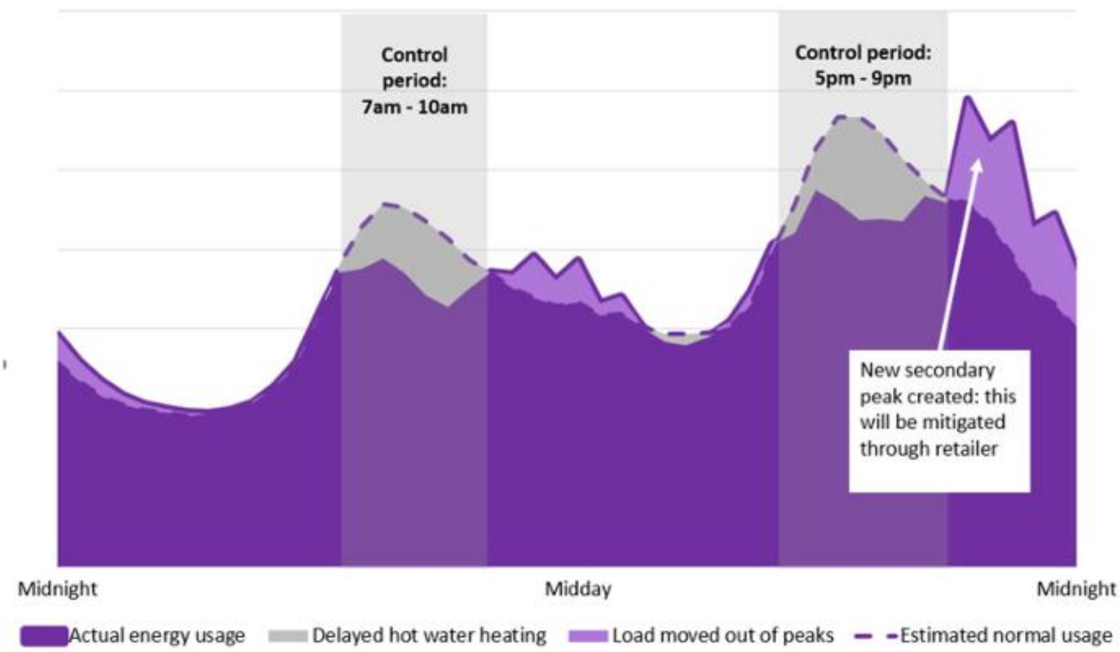
Figure 6 Retailer smart load control




In winter 2024, we ran a trial with several retailers to pilot this model. We retain the ability to override retailer instructions in the event of a local or national system emergency. It has been very popular with over 30,000 customers signed up in the first year. Our early experience is that retailers switching off individual hot water cylinders during the morning peak in the electricity spot market (dashed line) has taken nearly 10% off the peak load that we would otherwise have experienced but without having to turn every single cylinder off. The shift in load is illustrated in Figure 7.

Currently, spot market peaks happen at the same time as peaks on our network. Over time this may change as we see more intermittent generation (particularly solar) on our network. We are keen to work with retailers to see how we could use local pricing on the controlled network to defer specific planned investments.

Figure 7 Summarised load of 20,000 ICPs participating in hot water load shifting trial, 26 June 2024



In the medium term, we expect to see an increasing proportion of load on our network controlled by retailers and other parties rather than us directly. A priority as we transition to this change in network control, will be agreeing operating protocols for routine and emergency situations. This will need to be resolved before we are able to look at the future of our pricing for, and investment in, control plant.

### Developing a local flexibility market platform

We successfully applied for an Innovation and Non-Traditional Solutions Allowance (INTSA) to collaborate with Our Energy, Vector, and Unison to develop a local flexibility market platform. This platform will enable EDBs to broadcast requirements and procure local flexibility, while engaging flexibility service providers to register their distributed energy resources. This lowers the friction and transactional barriers for procurement.

We are progressing a scaled demand flexibility trial in partnership with EECA to test scaling demand response in mass market communities. The initial demonstration will be Ōmokoroa, based on rapid housing growth, a diversity of housing stock, and the presence of both emerging and existing DER. We will explore how different technologies and customer behaviours can be combined to deliver meaningful flexibility. Deployment will involve using a mix of flexible technologies, from batteries and heat pumps to smart hot water and appliance control. The results will inform future flexibility programmes and pricing approaches. This demonstration in Ōmokoroa is looking to defer ~$20 million of electricity network investment. This project aims to recruit 300-500 new batteries, 200 HEMS, and behavioural control homes, testing our D1, D2, and D3 flexibility product framework at scale.

### Active market procurement

A fundamental Powerco principle for procuring flexibility services is that they must provide optimal benefit to customers. This means in many cases, that flexibility will be sourced from third-party providers, including retailers and aggregators. These parties are often not only more efficient at providing flexibility solutions but are frequently able to realise more of the electricity value chain than Powerco can do on its own. This value chain can include distribution and transmission services, energy procurement and retailing, energy arbitrage, and reserves market.

Contract negotiations are progressing with multiple providers, with the aim of building a diversified portfolio of flexibility contracts, complementing traditional network reinforcement with additional tools to manage constraints and seasonal peaks. Initial agreements are for long-term contracts. As flexibility markets continue to grow, we are also likely to see an increase in short-term or day-ahead contracts.

Current and closed opportunities are detailed on our website include seeking non-network solutions for Mt Maunganui, Waihi Beach, Tahuna, Otumoetai, and the Northern Coromandel Peninsula. Market procurement will evolve and some standard procurement approaches emerge as EDBs and other parties progress with individual flexibility tenders, or process initiatives. For example, the Our Energy local market platform involves at least three EDBs so will offer a standardised approach at least to some extent if adopted by those EDBs.

Jurisdictions that are ahead of New Zealand in the DSO journey do offer some learning opportunities about procurement approaches, as mentioned in the joint letter, however even those examples such as the UK are shifting as they continue to learn themselves. A combined approach of learning, trialling, and sharing will best inform emerging approaches, rather than regulator direction on one approach.