From: Graeme Weston <[redacted]>
Sent: Monday, 6 April 2026 7:00 pm
To: market.regulation@comcom.govt.nz
<market.regulation@comcom.govt.nz> Subject: Submission - Horizon Networks Upgrade Program

Dear Commerce Commission

With reference to the attached Eastern Bay news article outlining Horizon Networks' proposed $225 million investment programme, including the Ōpōtiki upgrade, I wish to make a submission from a consumer perspective.

Please also find attached my formal submission for your consideration.

The article describes a conventional capital-led approach, with upgrades justified on forecast demand growth and to be recovered from consumers over time. While this may have been consistent with past practice, I note that the joint letter of 24 February 2026 from the Electricity Authority, Commerce Commission and EECA establishes a clear expectation that non-network solutions (NNS) — including distributed generation, batteries, and demand flexibility — should be prioritised and actively developed before committing to capital expenditure.

My concern is that the current proposal reflects a business-as-usual approach, where NNS are considered at a high level but not demonstrated at meaningful scale as a credible alternative to deferring or reducing investment.

This issue is also relevant to a parallel process currently before Parliament. The Trust Horizon Deed Variation Bill proposes to broaden the Trust's purpose away from energy-related activities. This risks diverting capital away from precisely the types of non-network investments — solar, storage, EVs, and flexibility — that could reduce peak demand, defer network upgrades, and lower long-term costs for consumers.

In my view, these two processes are directly linked. The Commission has an opportunity to ensure that network investment decisions reflect modern system capabilities and deliver least-cost outcomes for consumers, rather than locking in long-life assets ahead of fully testing lower-cost alternatives.

I respectfully request that the Commission apply a forward-looking test to Horizon Networks' proposal and require clear evidence that non-network solutions have been actively developed, trialled, and assessed at scale before approving further capital expenditure.

Regards
Graeme Weston
Electricity consumer, Eastern Bay
of Plenty [redacted]

Horizon Networks Investment Programme

Submission to the Commerce Commission

Subject: Horizon Networks – 10-year investment programme (including Ōpōtiki upgrade)
Submitter: Graeme Weston, electricity consumer (Eastern Bay of Plenty)
Date: 6 April 2026

---

1. Purpose of this submission

I request that the Commission **withhold approval** of Horizon Networks' proposed capital programme until it is satisfied that **non-network solutions have been fully and transparently evaluated** in line with the joint expectations set on 24 February 2026 by the Electricity Authority, Commerce Commission and Energy Efficiency and Conservation Authority.

---

2. Context

Horizon proposes approximately **$225 million** of investment over ten years, including the **Ōpōtiki 11kV to 33kV reinforcement (~$14.3m)** and other capacity and resilience upgrades. These proposals respond to growth and electrification pressures. However, they also represent **long-lived additions to the regulated asset base (RAB)**, with costs recovered from consumers over decades via depreciation and WACC.

2A. Role of Trust Horizon and alignment with non-network solutions

Trust Horizon has indicated that it holds approximately **$200 million in assets** and is seeking to broaden its Trust Deed to enable distribution of funds into general charitable activities beyond energy-related purposes. In the context of the proposed network investment programme, this is a material consideration. The same capital represents a significant opportunity to support **non-network solutions** that directly align with Horizon Networks' emerging needs—specifically, the deployment of distributed solar, batteries, electric vehicles, and flexible demand. These technologies can reduce peak demand, improve utilisation of existing assets, and defer or avoid capital expenditure. Rather than diverting funds away from the energy system, Trust Horizon is uniquely positioned, as owner, to **co-invest or facilitate investment** in these solutions at scale, using low-cost capital to achieve measurable reductions in long-term electricity costs for consumers. This would be consistent with the expectations set out in the 24 February 2026 joint letter and would provide a practical pathway to deliver the least-cost outcome for the community.

---

3. Regulatory expectation (24 February 2026 joint letter)

The joint letter explicitly calls on distributors to:

- **prioritise non-network solutions (NNS)** such as distributed generation, batteries, and flexible demand,
- **use price signals** to manage peaks and constraints, and
- **demonstrate** that NNS have been considered before committing to capital.

This establishes a clear expectation on **sequencing**:
NNS first → quantify impact → then determine residual CAPEX.

---

4. Deficiency in the current proposal

Based on publicly available material, the proposal **does not yet demonstrate**:

1. The **peak demand reduction achievable** through targeted DER and flexibility on affected feeders (including Ōpōtiki).
2. How such reductions would **defer, resize, or phase** the proposed upgrades.
3. A **consumer cost comparison** between:
   - CAPEX-first (add to RAB, recover via WACC), and
   - NNS-first (avoid or defer CAPEX).

Proceeding to full capital approval without this analysis risks **over-investment** and **locking consumers into avoidable long-term costs**.

---

5. Ōpōtiki feeder – targeted NNS alternative (illustrative)

The Ōpōtiki upgrade is justified by peak and capacity constraints. Those constraints are **peak-driven**. A targeted NNS portfolio could include:

- rooftop solar + batteries on constrained feeders,
- controllable hot water and EV charging,
- time- and location-based price signals,
- aggregation to deliver **reliable peak reduction**.

Even modest participation can be material. For example, if **300–500 households** each deliver **2–3 kW** of peak reduction (via batteries/load shifting), that is **0.6–1.5 MW** of peak relief. At scale, this can **defer or reduce** the need for reinforcement and **stage** investment rather than commit upfront.

5A. Precedent: application of non-network solutions at scale

A relevant precedent is the Queenstown Electricity Accelerator led by Rewiring Aotearoa. That initiative is addressing a comparable problem—forecast growth and peak-driven constraints—by prioritising distributed energy resources and demand flexibility ahead of traditional network reinforcement. The objective is to defer or avoid significant capital investment by coordinating rooftop solar, batteries, and controllable load as a system resource.

While Queenstown's constraints sit primarily at the transmission interface and Horizon Networks' proposals are at the distribution level, the underlying economics are the same: networks are built for peak demand, and reducing those peaks can materially change investment requirements. The

Queenstown programme demonstrates that non-network solutions can be organised, measured, and procured at scale, providing a credible alternative pathway that is consistent with recent regulator expectations.

In this context, Horizon Networks' investment programme should be assessed not only against traditional engineering standards, but also against established non-network precedents. At a minimum, this precedent supports the need for rigorous evaluation of distributed energy and flexibility options before committing to long-life capital investment that will be recovered from consumers over several decades.

5B. Ōpōtiki upgrade in the context of recent generation investment (Waiotahe)

The proposed Ōpōtiki reinforcement should be considered alongside recent generation developments in the same part of the network, in particular the Te Herenga o Te Rā (Waiotahe) Solar Farm and associated substation upgrades. These investments demonstrate that significant capital is already being deployed to accommodate renewable generation within the region.

The Horizon Networks reopener application (September 2025) indicates that non-network solutions were considered as part of the optioneering process. However, this assessment reflects regulatory expectations at that time, where non-network solutions were typically evaluated as alternatives rather than actively developed or procured at scale.

The joint letter of 24 February 2026 from the Electricity Authority, Commerce Commission and Energy Efficiency and Conservation Authority materially raises this expectation. It signals a shift toward *actively deploying* distributed energy resources, flexibility, and demand response as part of least-cost network planning, rather than treating them as theoretical options.

In this context, the issue is not whether Horizon Networks complied with prior requirements, but whether the proposed investment pathway remains consistent with current expectations. The presence of large-scale solar generation at Waiotahe further reinforces the opportunity to integrate generation, storage, and flexible demand to reduce peak load and improve utilisation of existing assets.

I therefore request that the Commission apply a forward-looking test to the Ōpōtiki upgrade and wider programme. This should include a requirement for Horizon Networks to demonstrate, prior to full commitment of capital, that non-network solutions have been actively developed, trialled, and assessed at meaningful scale, and that the proposed investment represents the least-cost outcome for consumers under current regulatory expectations.

This approach does not seek to unwind prior decisions. It ensures that future commitments are made in a manner consistent with the evolving regulatory framework and the long-term interests of consumers.

Without such a forward-looking test, there is a risk that legacy investment approaches continue by default, even where lower-cost alternatives are now available.

---

6. Consumer cost impact

- **CAPEX-first:** Adds to RAB → consumers pay **depreciation + WACC for 30–40 years**.

- **NNS-first: Avoids or defers** that addition → **permanent cost avoidance**, not temporary relief.

The difference is structural. Once assets are built, costs are **locked in**.

---

7. Requested conditions

I request the Commission require Horizon Networks to provide, for each major upgrade (including Ōpōtiki):

1. **NNS Potential Assessment**
   - MW of peak reduction achievable
   - kWh shifted/avoided at peak
   - participation assumptions and delivery certainty
2. **Options Analysis**
   - CAPEX-first vs NNS-first vs hybrid
   - impact on **timing, scale, and phasing** of upgrades
3. **Consumer Cost Comparison**
   - NPV of costs to consumers under each option
   - explicit treatment of **RAB/WACC impacts**
4. **Procurement Plan**
   - how Horizon will **procure flexibility** (tariffs, contracts, pilots)
   - timelines and **trial at meaningful scale**
5. **Reporting**
   - annual reporting of **avoided CAPEX**, peak reductions, and consumer savings

Approval should be **conditional** on this evidence.

---

8. Conclusion

I acknowledge the need to maintain reliability and support growth. However, the **24 February 2026 joint letter** makes clear that distributors must **exhaust lower-cost non-network solutions first**.

I therefore request that the Commission **deny or defer approval** of the proposed capital programme until Horizon Networks demonstrates that it has met these expectations and that the chosen pathway represents the **least-cost outcome for consumers**.

The risk is not under-investment. The risk is committing to long-life assets before fully testing lower-cost alternatives.

Graeme Weston
Electricity consumer, Eastern Bay of Plenty
[redacted]

IN THE MATTER OF

Part 4 of the Commerce Act 1986

AND

The long-term benefit of electricity consumers in the Eastern Bay of Plenty

Supplementary Submission

Horizon Networks Investment Programme — in addition to submission of 6 April 2026

Submitted by: Graeme Weston (HEDL Consumer), Ōhope, Eastern Bay of Plenty

Date: 28 June 2026

1. Purpose of this supplementary submission

This submission supplements, and does not withdraw or replace, my submission of 6 April 2026 regarding Horizon Networks' 10-year investment programme, including the Ōpōtiki sub-transmission reinforcement. Since 6 April, five further points have become available or apparent that materially strengthen the case made in that submission. I provide them here as additional support for the same requested conditions, set out in Section 7 of the original submission.

2. Confirmation that the price signal needed for NNS does not yet exist

Horizon Networks' own Delivery Price Schedule, effective 1 April 2026, discloses an Export Charge – Peak of \$0.03428/kWh for both Low User Domestic Urban and Rural Time of Use categories, against a Time of Use Charge – Peak (import) of \$0.13572/kWh for the same categories. The peak export rate is approximately one quarter of the peak import rate.

This is directly relevant to a point Horizon Networks itself raised in its 11 March 2024 submission to the Commission on the DPP4 capex workshop, in which it stated: "a recent internal review of consumers on a time-of-use price (that is passed through by the retailer), found there was very limited consumer response to the peak period price signals, despite potential savings in doing so."

The now-published 1 April 2026 rate schedule offers a plausible, quantified explanation for that limited response: a peak export rate set at roughly one quarter of the corresponding import rate provides materially weaker financial incentive for a household or business to invest in battery storage and discharge into the network at peak than a cost-reflective rate would. The absence of consumer response evidenced by Horizon's own review may therefore reflect the price signal itself, rather than consumer indifference to cost savings.

This bears directly on the "Procurement Plan" condition requested in Section 7 of my 6 April submission — specifically, how Horizon proposes to procure flexibility through tariffs and contracts. I ask that the Commission treat Horizon's own published export rate as evidence relevant to assessing whether its current pricing approach is capable of delivering the NNS uptake referred to in the 24 February 2026 joint letter, or whether it requires revision before any conclusion can be drawn about NNS viability on Horizon's network.

3. Clarification of the technical mechanism at Ōpōtiki: voltage drop is load-dependent, not constant

Horizon Networks' reopener application (23 September 2025) confirms that the Ōpōtiki constraint is a function of voltage drop over approximately 50km of 11kV feeder, and that the resulting low-voltage events are tied to high load periods rather than being a constant, all-hours condition. The application's own Figure 4 (historic voltage measurement) and the statement that new transformers will "resolve voltage compliance risks during high load periods" both support this.

This confirms that the existing 11kV network has genuine spare capacity outside peak periods, and that a non-network solution targeting peak-period current reduction — rather than requiring new generation capacity per se — is the technically relevant intervention. This sharpens, rather than alters, the NNS alternative described in Section 5 of my 6 April submission: the relevant metric for any NNS portfolio at Ōpōtiki is dispatchable peak-period discharge capacity, not total energy or generation volume.

4. A disclosure-based mechanism for applying this generally, not as a single-case request

I am conscious that the Commission's general preference is to regulate through sector-wide input methodologies and price-quality paths rather than review individual investment decisions on a case-by-case basis. I raise this to make clear that the request below is intended as a general disclosure standard, illustrated using Ōpōtiki as a worked example — not a request specific to the Ōpōtiki feeder alone.

I therefore ask that, in addition to the conditions sought in Section 7 of my 6 April submission, the Commission consider requiring, as a general disclosure standard applicable to any EDB seeking reopener or CPP approval for system-growth expenditure:

- Publication of the EDB's congestion/constraint map and the time-of-day profile of the relevant constraint (i.e. whether the binding constraint is peak-only or constant), at the time of application;
- Disclosure of the EDB's current locational and time-of-use distribution price signals applicable to that constrained area, including import and export rates, so that the Commission and submitters can assess whether the pricing in place is capable of eliciting the NNS response the EDB's optioneering assumed or rejected; and
- Where an EDB's optioneering analysis concludes that third-party DER uptake is forecast to lag organic growth, disclosure of the price signal assumed in reaching that conclusion.

Ōpōtiki provides a clear illustration of why this would assist the Commission's assessment: Horizon's reopener application concluded that historic battery uptake had “no material influence in reducing peak demand,” but the application does not disclose what price signal, if any, was available to consumers over the relevant period. Horizon's own 1 April 2026 schedule, now available, suggests the signal was and remains weak. A general disclosure standard of this kind would allow this to be assessed consistently across all EDBs and all future reopener or CPP applications, consistent with the Commission's stated preference for sector-wide rather than case-specific mechanisms.

5. EDBs should declare the wider value-add benefits of grid injection, and increase the share of avoided cost returned to participants

The price-signal deficiency identified in Section 2 above is a symptom of a narrower underlying problem. Horizon's published export rate values injected energy only as energy — it does not reflect the wider value that a battery or EV discharging at a constrained feeder during a peak period can provide by offsetting business-as-usual (BAU) network investment. That wider value can include deferred or avoided growth in the regulated asset base (RAB), reduced distribution and transmission losses, resilience and avoided-outage benefit, and local economic retention, in addition to the energy itself.

This matters directly to the Ōpōtiki assessment. If the only value Horizon recognises for a peak-period injection is the energy value reflected in its Export Charge – Peak, then neither Horizon nor the Commission can properly test whether a non-network solution is being fairly priced against the BAU reinforcement it could defer or avoid. The relevant comparison is not the export tariff against the import tariff; it is the export tariff against the full avoided cost of the network investment the injection displaces.

I therefore ask that, in addition to the disclosure standard sought in Section 4, the Commission require Horizon Networks, and consider requiring generally of any EDB seeking reopener or CPP approval for system-growth expenditure, to:

- declare, for any constrained area where DER or flexibility is proposed as an alternative to network capex, the wider value-add benefits attributable to injection at that location and time — including deferred or avoided RAB growth, reduced losses, resilience and avoided-outage value, and local economic value — not only the energy value reflected in the export tariff; and

- disclose what percentage of that total avoided-cost value is currently returned to the participating consumer through the export tariff, and increase that percentage, or explain why it should not be increased, so that the price signal reflects a fair share of the value the participant's asset creates rather than energy value alone.

Without this, there is a risk that EDBs under-price DER participation by design rather than by evidence: a narrow, energy-only export rate will always look small next to the cost of a substation or feeder upgrade, even where the injection is in fact avoiding a material share of that cost. Requiring EDBs to declare the wider value and the share returned to participants would let the Commission test whether current pricing, including Horizon's, is capable of eliciting efficient NNS uptake, or whether consumers who invest in distributed generation and storage are being asked to subsidise BAU network expansion rather than being paid a fair share of the cost they avoid for the network as a whole.

6. National-economy case: recognising V2G as a strategically important technology for accelerated adoption

The points above concern how Horizon and other EDBs should price and disclose the network value of distributed injection. There is a related, larger point that goes beyond any single network's price-quality path. Bidirectional charging and V2G-capable EVs, combined with rooftop solar, are not only a network-deferral tool at the level of an individual feeder. At national scale they can reduce imported transport fuel, defer network capital expenditure across many EDBs, improve resilience during dry-year and outage conditions, absorb surplus renewable generation that would otherwise be spilled, reduce reliance on peaking plant, and retain energy spending inside local communities rather than sending it offshore as fuel imports.

New Zealand's most significant energy-security exposure is the dry-year hydro shortage risk, which is not solved by any single strategy and for which no single party currently has strong enough incentive to invest in assets that may only be called on once a decade. A large, distributed, bidirectionally-capable EV fleet is a candidate flexibility resource for exactly this kind of infrequent but high-value event, in a way that is materially cheaper than purpose-built standby generation, because the vehicles are purchased primarily for transport and the battery capacity already exists.

This national-economy dimension is broader than anything a single distributor's price-quality path can be expected to capture, and I do not ask the Commission to resolve it through the Horizon Networks investment programme. However, I ask that the Commission record, in its assessment of this and comparable investment programmes, that the value of V2G and distributed solar is not confined to the network benefits addressed in Sections 2 to 5 above, and that accelerated adoption of bidirectional charging and V2G-capable vehicles has a plausible national-economy case that extends to fuel-import substitution, dry-year energy security, deferred network and generation investment nationally, and resilience.

I ask that the Commission draw this to the attention of the Electricity Authority and government as a matter that, in my submission, warrants active consideration of policy settings to accelerate adoption of bidirectional charging and V2G-capable vehicles at a national level, including standards for bidirectional-capable chargers and EVs, and clarity on how V2G availability and dispatch would be recognised and rewarded across the wider electricity market, not only at the distribution level addressed in this submission.

7. Conclusion

These five points are offered in support of, and do not alter, the conditions requested in my 6 April 2026 submission. I continue to request that the Commission require Horizon Networks to provide the NNS Potential Assessment, Options Analysis, Consumer Cost Comparison, Procurement Plan, and Reporting set out in Section 7 of that submission, and I ask that the evidence above — Horizon's own published export rate, the load-dependent nature of the Ōpōtiki voltage constraint, the case for a general disclosure standard, the case for declaring the wider value-add benefits of grid injection and increasing the share of avoided cost returned to participants, and the national-economy case for accelerated adoption of V2G — be taken into account in that assessment.

Graeme Weston

24 February 2026

Tēnā koutou,

Ensuring consumers benefit from efficient investment in non-network solutions

Consumers will benefit significantly from the use of non-network solutions in delivering the capacity needed for the energy transition and for economic growth. This is a joint letter from the Commerce Commission, the Electricity Authority and the Energy Efficiency and Conservation Authority focused on accelerating the use of non-network solutions in electricity distribution networks.

Purpose of this letter

This letter sets out our understanding of the opportunity that non-network solutions offer to improve the efficiency of electricity distributors (distributors). It also sets out some of the key actions we consider distributors should be taking now and in the future to leverage non-network solutions effectively and efficiently. [1]

We are seeking feedback on the contents of this letter from all stakeholders with an interest or involvement in this area. This includes consumer groups, distributors, flex providers, generators, retailers and Transpower.

Your feedback will help inform future thinking on priorities, work programmes, and new/amended regulatory requirements. These include Electricity Authority Te Mana Hiko (Authority) work on network pricing and policy, the Energy Efficiency & Conservation Authority Te Tari Tiaki Pūngao (EECA) work supporting non-network solutions and the Commerce Commission Te Komihana Tauhokohoko (Commission) preparation for the next default price path (DPP5), ongoing work on information disclosure requirements and assessment of reopener applications.

Our role

As regulators and agencies with statutory responsibilities in the electricity sector, the Authority, Commission, and EECA each play distinct but complementary roles in shaping how New Zealand's electricity system evolves. This letter focuses on our common goal – supporting an electricity system that delivers the best long-term outcomes for consumers.

While our responsibilities differ, we collectively shape the regulatory settings that guide how electricity distribution businesses plan and invest in their networks. These settings matter because

[1] Non-network solutions (NNS), also referred to as "non-traditional solutions," are alternatives to traditional network reinforcement that address an identified network need. NNS may include flexibility services (where electricity use or generation is adjusted by customers or third-party providers in response to signals or contracts), distributed energy resource orchestration, demand reduction, distributed generation, energy efficiency, or other commercial arrangements that reduce or shift load so that network upgrades can be deferred or avoided.

distribution investment requires long lead times, is slow and costly to change once initiated with the costs and benefits of decisions ultimately borne by consumers.

Distribution infrastructure underpins almost every aspect of modern life

Decisions about when and where networks are reinforced, and whether consumer and system needs are met through network or non-network solutions, directly affect household electricity bills, the cost of the energy transition (such as electrifying transport, process heat and gas hot water and space heating), and the affordability and reliability of energy for businesses and communities across New Zealand.

Through our respective roles, we seek to ensure distribution investment decisions are efficient, forward-looking, responsive to changing system needs and deliver reliable, least-cost electricity at for consumers. We also recognise the role we play in aligning regulation across government to minimise regulatory burden and simplify processes for market participants, to enable the opportunity outlined in this letter.

Why now

The electricity system is changing rapidly. Renewable generation is growing, bringing greater variability and intermittency. At the same time, overall demand is projected to rise as gas supply declines, transport electrifies, and more industrial and commercial processes transition to electric technologies.

Alongside these changes, new distributed energy resources (DER), including solar, batteries and smart, controllable devices, are becoming more affordable and more widely deployed. With the right signals and frameworks, they can respond dynamically to system conditions and play a significant role in supporting the wider electricity system.

Non-network solutions offer significant, quantifiable potential to reduce costs and defer network upgrades

If this potential for flexibility is unlocked, it can deliver meaningful benefits for consumers and the system. By shifting electricity use away from peak periods and better aligning demand with available network capacity, flexibility can reduce pressure on upstream networks, lower the need for high-cost generation and defer or avoid expensive network upgrades.

Non-network solutions can also buy time before committing to major upgrades and allow network owners to refine their forecasting and demand assumptions. This means when (or if) reinforcement is needed, it is based on better information and more accurate cost-benefit analysis.

The scale of this opportunity is becoming increasingly clear. EECA's recent analysis suggests that, with suitable investment and incentives, there is 1.9GW of potentially shiftable load in the system now, with a further 500MW of sheddable load available.[2]

With distributors forecasting approximately $2 billion in system growth capex from 2026 to 2030, leveraging these non-network solutions efficiently brings a meaningful opportunity to improve performance and reduce costs for networks, consumers and the wider electricity market.

[2] EECA, "The full potential of flexible electricity in New Zealand," (January 2026).

Realising these benefits requires coordinated action across the electricity sector

All key system actors need to play their part in providing the signals, incentives and opportunities that enable participants, including consumers, to fully utilise their flexibility. Open, interoperable approaches, including standardised communication, data exchange and cybersecurity practices, will be essential to enable seamless integration of DER and avoid fragmented solutions that limit consumer value.

What distributors can do

The steps outlined in this letter focus on opportunities to ensure distributors are efficiently leveraging non-network solutions. However, we are similarly focused on other actors in the electricity market to ensure consumers receive the services they demand at an efficient price. To that end, we also welcome feedback on any other actions the Authority, Commission and EECA could take to support the efficient utilisation of flexibility services in New Zealand.

1. Ensure both non-network and network solutions are considered in network planning

Distributors should treat both non-network and network solutions on an equal footing throughout planning processes, as well as their longer-term strategy for managing their networks. This is supported by using objective, comparable, consistent and transparent criteria (eg, net-present-value/cost-benefit analysis, deliverability).

Doing so helps distributors ensure that opportunities to efficiently use non-network solutions are identified early, clearly signalled and given sufficient lead time to be developed and tested so they have a genuine opportunity to address the identified need.

This expectation is consistent with the Commission's Asset Management Plan (AMP) requirements for distributors to identify constraints, assess non-network alternatives, and disclose where these may provide a more cost-effective option than traditional network reinforcement. It also aligns with the expenditure incentive settings under the Commission's price-quality regulation framework - which are technology-neutral and financially balanced, so distributors retain a share of efficiency gains from the least-cost solution whether delivered through opex or capex.

There is significant material from overseas energy markets that can help distributors further develop and mature their network planning processes so non-network solutions are considered on a consistent and comparable basis. This is complemented by workstreams underway in New Zealand, being undertaken by Electricity Networks Aotearoa, the Electricity Engineers' Association and FlexForum.

There are overseas examples of relevance to New Zealand, including the Energy Networks Association in the United Kingdom commissioning Baringa Partners to develop the Common Evaluation Methodology – a standardised cost-benefit evaluation framework used by all of its members to fairly compare the traditional network reinforcement against procuring flexibility services.[3]

Similarly, it has a range of operational, commercial and technical guidance via its Open Networks programme to help ensure its members are integrating non-network solutions efficiently into their networks.[4]

---

[3] Available here.

[4] More information here.

2. Pricing as an enabler of flexibility

Pricing is a critical lever for making better use of the electricity network and lowering costs for consumers. When prices clearly signal when capacity is available and when it is constrained, electricity use can shift in ways that reduce peaks and defer network investment.

We want pricing to support a future where electricity use is price-responsive rather than being directly controlled by distributors. In this future state, consumers are not expected to actively manage their electricity use day-to-day. Instead, they choose retail products and services that suit their preferences. In addition, retailers or other customer agents respond to network price signals on their behalf, using automation and smart technology to manage assets such as EV chargers, batteries and hot water systems.

Pricing should therefore be designed to enable and reveal price-responsive flexibility over time, rather than assume it appears automatically or remains static. This requires distributors to look beyond directly controlled load and to actively test, monitor and refine pricing structures so they can understand how demand responds and how those responses can increasingly be incorporated into system operation and network planning.

We also recognise that reforms to enable price-responsive flexibility will influence the role and attractiveness of existing controlled load arrangements, such as ripple control, which deliver flexibility through direct network control.

Controlled load can continue to provide system value, particularly during the transition, and pricing should reflect that value where it exists. Controlled load arrangements should remain clear, fair and deliver tangible, straightforward value to consumers, without weakening broader price signals intended to support flexible, automated responses.

To support this direction, the following aspects from the Authority's May 2024 open letter to distributors on Distribution Pricing Reform[5] are particularly relevant:

- Align off-peak and controlled load charges with their low long-run marginal cost (LRMC) – typically close to zero – to encourage demand shifting and EV charging when network capacity is available.
- Make off-peak pricing simple and attractive, recognising that responses will largely be delivered through retailer products and automation rather than manual consumer action.
- Monitor and manage transition risks, including the risk of new peaks forming at pricing boundaries.
- Review non-residential tariffs (eg, flat kWh or capacity charges) to ensure they do not discourage efficient consumption or flexibility.
- Build on existing progress and share learnings. Many distributors have already reduced off-peak rates significantly, with some achieving zero-cost off-peak pricing. Sharing examples like this, of best practice, through industry forums, AMP disclosures or case studies, can help distributors earlier in their pricing reform journey adopt effective approaches more quickly. It also supports consumer understanding and uptake of new tariffs, ensuring that price signals translate into real flexibility outcomes.

[5] Electricity Authority, "Open letter to distributors" May 2024.

3. Engaging with the market

As New Zealand's market for non-network solutions is still developing, procurement and engagement processes need to be designed to encourage participation and reduce barriers for providers.

In practice this means:

- Standardising or coordinating approaches to seeking market offers for flexibility, so providers do not have to navigate 29 different procurement processes.
- Learning from established frameworks in the European Union and United Kingdom, as well as from trials already run in New Zealand, to expedite the implementation of mature procurement approaches.
- Clearly signalling and supporting the use of open communication protocols as the preferred direction for non-network solutions, to enable interoperability, reduce integration costs, and avoid fragmented or proprietary approaches that limit market participation. Consistent use of open protocols can lower barriers for providers, support competition and make it easier for flexibility services to scale across multiple networks over time.
- Demonstrating why any in-house non-network solution represents the most efficient option, compared with what the market could provide. Given distributors' natural monopoly position, and the associated risk of real or perceived leverage into adjacent flexibility services markets, this requires transparent and robust analysis, documented through disclosures or AMPs, showing how in-house options were assessed against market alternatives and why they deliver the greatest value for consumers. The Authority's 'Guidance on distributor involvement in the flexibility services market' should inform this approach to ensure competition is not inhibited and market development is supported.[6]
- Contributing to price discovery for flexibility services by publishing indicative costs, sharing learnings from procurement processes and supporting transparency. This helps build confidence in the market, encourages participation and ultimately drives down the cost of non-network solutions for consumers.

Next steps

We invite responses from stakeholders on the contents of this letter by 24 March 2026 to distribution.feedback@ea.govt.nz. Please use the subject line *"Response to joint letter to distributors on NNS."*

We (the Commission, Authority and EECA) intend to publish feedback we receive unless there is a clear and explicit request to not publish it due to confidentiality or commercial sensitivity. We will consider any such requests on their merits.[7]

Feedback will help inform our future thinking, priorities, and respective work programmes. We will continue to engage with you to monitor progress and identify any regulatory or operational barriers. Your leadership in this area is critical to achieving a future-ready electricity system.

[6] Electricity Authority, "Guidance on distributor involvement in the flexibility services market," (2 Feb 2026).

[7] Please note, your submission may still be released under the Official Information Act 1982, even if not published. The Authority would normally consult with you before releasing any material that you said should not be published.

Thank you for your commitment to this important work.

[redacted]

Andy Burgess, General Manager, Infrastructure Regulation
Commerce Commission Te Komihana Tauhokohoko

[redacted]

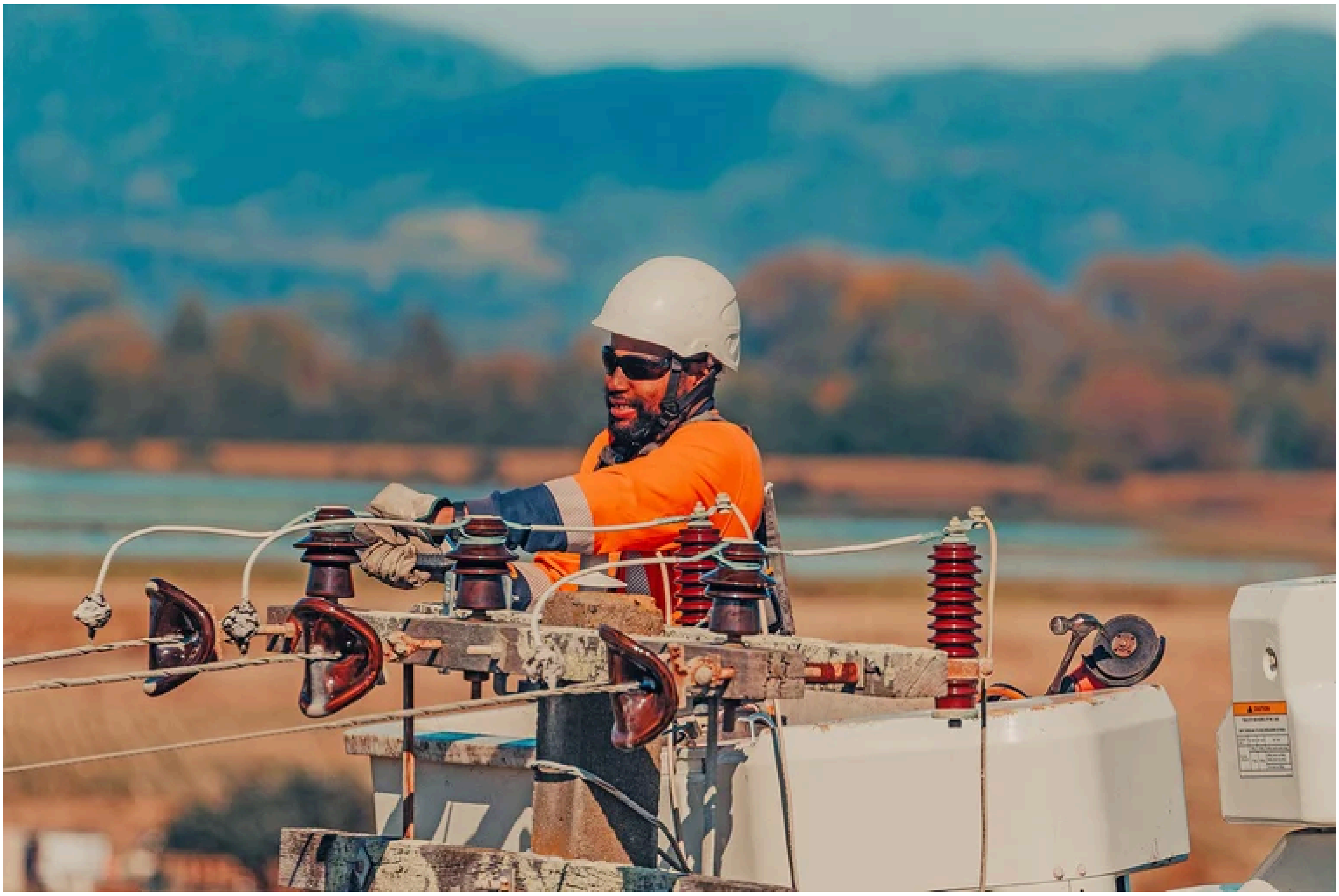
Sarah Gillies, Chief Executive
Electricity Authority Te Mana Hiko

[redacted]

Dr. Marcos Pelenur, Chief Executive
Energy Efficiency and Conservation Authority Te Tari Tiaki Pūngao

Thu, Apr 2, 2026 4:01 AM

Horizon Networks powering the Eastern Bay



on the job: Line mechanic Itai Mabvurira, working on one of the Horizon assets.

.

Horizon Networks has unveiled a comprehensive 10-year, $225 million investment plan designed to power the Eastern Bay for decades to come.

As part of Horizon Energy Group and 100 percent owned by Trust Horizon, Horizon Networks is prioritising infrastructure that is more resilient to adverse weather events and enables regional economic growth, while facilitating the transition to a low-carbon future.

Horizon Energy Group chief executive Ajay Anand said the investment was a key foundation for the Eastern Bay's continued growth and prosperity.

"Our region is undergoing a significant transformation, from the expansion of the aquaculture and kiwifruit industries in Ōpōtiki to industrial developments in Kawerau and increased development in Whakatāne.

"The demand for electricity is increasing rapidly, with growing expectations for networks to deliver a safe, reliable supply while ensuring sufficient available capacity to support economic growth, electrification, and long-term energy resilience," said Mr Anand.

"The plan seeks to balance investment in a safe, reliable, and sustainable electricity network with the need to keep energy costs affordable for the communities we serve. This $225 million commitment ensures our infrastructure doesn't just keep up with growth but actively drives it."

The first major milestone of the plan is a $14.3 million upgrade to the Ōpōtiki electricity supply from 11kV to 33kV, as the system is forecast to reach its capacity. The project is scheduled for completion in 2027.

"Upgrading the Ōpōtiki sub-transmission system is essential to support the district's growing primary industries and surrounding infrastructure developments," said Mr Anand.

To fund this work, Horizon Networks has submitted an application to the Commerce Commission for a pricing adjustment. If approved, the investment is estimated to result in a modest price increase for most residential consumers.

The Commerce Commission will be undertaking a consultation on Horizon Network's application in due course, and Horizon Networks encourages the community to provide feedback.

"We are acutely aware of the cost-of-living pressures facing our families and businesses. We have worked hard to ensure this investment delivers the greatest value.

"For most households, the estimated cost is between $3 and $4 per month. It is a necessary investment to ensure our network is resilient against increasing storms and ready for the shift toward low-carbon technologies."

"This is about more than just poles and wires. It is about ensuring the Eastern Bay of Plenty remains a resilient and attractive place to live and do business for generations to come," said Mr Anand.

As a locally owned company, Horizon Networks' performance provides direct returns to the community through Trust Horizon, which has reinvested $50 million into local initiatives to date.

Find out more about the investment plan on Horizon Networks website https://horizonnetworks.nz/powering-the-eastern-bay/

outdoor switchyard.

IN THE MATTER OF

Part 4 of the Commerce Act 1986

AND

Horizon Networks' Ōpōtiki foreseeable large reopener draft decision [CCNZ-IMANAGE.FID463197]

Second Supplementary Submission

Horizon Networks Investment Programme — in addition to submissions of 6 April 2026 and 28 June 2026

Submitted by: Graeme Weston (HEDL Consumer), Ōhope, Eastern Bay of Plenty

Date: 17 August 2026

1. Purpose of this second supplementary submission

This submission supplements, and does not withdraw or replace, my submission of 6 April 2026 or my supplementary submission of 28 June 2026 regarding Horizon Networks' 10-year investment programme, including the Ōpōtiki sub-transmission reinforcement. I understand from Harsim Ghuman's correspondence of 13 August 2026 that this matter is now at draft decision stage. I am providing this second supplementary submission now, while that decision is still open, because since 28 June I have examined a second, live non-network solutions case on Horizon's network — the Kope zone, including Whakatāne District Council's Whakatāne Museum site — and it has sharpened my understanding of a point that qualifies, without retracting, the case made in my earlier submissions: Horizon Networks has a legitimate and currently unresolved cost-recovery constraint of its own, and the Commission's assessment of the Ōpōtiki reopener should take it into account.

2. Horizon has a legitimate constraint that helps explain, without excusing, the pattern in my earlier submissions

My 28 June submission (Section 5) asked the Commission to require Horizon Networks to declare the wider avoided-cost value of distributed energy injection at constrained locations, and to increase the share of that value returned to participants through its export and flexibility pricing — on the basis that Horizon's published Export Charge – Peak (approximately one quarter of the corresponding import rate) is too weak a signal to elicit the non-network response the 24 February 2026 joint letter calls for.

Since making that submission, I have identified a further, related fact that I believe the Commission should weigh alongside it. Horizon Networks' own submission to the Electricity Authority states that current Part 4 settings can financially penalise an EDB for buying flexibility services rather than building network capex: opex spent on flexibility procurement sits unrecovered until the next regulatory reset, while capex begins earning a return immediately through the regulated asset base. Horizon has asked the Commission to treat flexibility-procurement opex as an eligible reopener category. I have checked the Commission's final reopener guidance, issued 25 September 2025, and it does not address this cost category — the gap Horizon has identified remains open, so far as I can establish from public documents.

I raise this not to soften the conditions requested in my earlier submissions, but to be fair to Horizon in how the Commission weighs them. The underpricing I identified in Section 5 of my 28 June submission and the recovery-timing gap Horizon has identified to the Electricity Authority are, in my view, two sides of one mechanism problem, not opposing positions. Even if Horizon wished to raise its export and flexibility rates to the level my 28 June submission requests, current settings give it limited financial means to do so at pace, because the additional opex this would represent is not straightforwardly recoverable in a timely way. A Commission response that requires better pricing and disclosure from Horizon (as I have asked) without also addressing this recovery constraint risks asking Horizon to absorb a cost timing penalty for doing the right thing.

3. A second live example: the Kope zone and Whakatāne Museum

Consistent with Section 4 of my 28 June submission — that this is intended as a general disclosure standard illustrated by Ōpōtiki, not a request specific to that feeder alone — I offer a second, independent illustration from elsewhere on Horizon's network.

Horizon operates a live, priced LocalFlex tender for the Kope zone substation (SUB Kope ZSS): $390–410/MWh, weekday winter mornings, tender rounds running June 2027 to August 2029, minimum 100kW portfolio. This is a genuine, current price signal of exactly the kind the 24 February 2026 joint letter is asking the market to respond to. However, for an individual candidate site — I have modelled Whakatāne District Council's Whakatāne Museum, a Tranche 2 solar site inside the Kope zone with a *battery-ready inverter decision still open* — my own independent estimate puts realistic annual flexibility income at roughly $120 to $620 a year. That figure is consistent with, and I believe further evidences, the underpricing concern raised in Section 5 of my 28 June submission: at current settings, the direct financial signal reaching an individual site is too small on its own to influence a *live council capital decision*, even where the wider avoided-cost case is substantial.

On that wider case: I have built an illustrative 40-year community-position model for the Kope zone choice, as a screening case rather than a final investment decision (Horizon would still need to confirm the underlying network need and service value, in the same way I have asked it to for Ōpōtiki). It shows the traditional network upgrade as a cost recovered from consumers with no offsetting return, against a non-network pathway with a materially positive net community value over the same period — an illustrative $8.6m difference between the two paths. I offer this only as a second worked example of the same national pattern described in my earlier submissions: a real, quantifiable gap between what non-network solutions could deliver for consumers and what current settings, on both the pricing side and the recovery-timing side, are currently able to elicit.

4. A further requested condition, additive to Section 7 of my 6 April submission

My 6 April submission (Section 7) asked the Commission to require Horizon to provide an NNS Potential Assessment, Options Analysis, Consumer Cost Comparison, Procurement Plan, and Reporting for each major upgrade, including Ōpōtiki, before capital approval. I do not resile from that request. I ask the Commission to add a further condition, addressing the recovery-side barrier identified in Section 2 above, so that the pricing and disclosure reforms I have requested are not undermined by leaving Horizon without a workable way to fund them:

- That the Commission consider extending its reopener guidance, or an equivalent mechanism, to explicitly include EDB flexibility-procurement opex as an eligible category — consistent with Horizon's own request to the Electricity Authority.
- As an alternative or complement, that the Commission consider a deferral or wash-up account for flexibility-procurement costs, under which payments accrue with interest at the Commission's allowed rate of return and are trued up at the next price-path reset — keeping Horizon financeable without ratepayers or consumers paying more in net present value terms, while removing a cash-flow penalty that has nothing to do with whether flexibility is the cheaper option.
- That any such mechanism be conditioned on the kind of Consumer Cost Comparison already sought in Section 7 of my 6 April submission — the EDB demonstrating that the flexibility spend is cheaper for consumers in net present value terms than the deferred capex alternative — so that faster recovery is evidence-based rather than automatic.

5. Conclusion

I ask that this second supplementary submission, together with my submissions of 6 April and 28 June 2026, be taken into account in the Ōpōtiki reopener draft decision, and that the point raised in Sections 2 and 4 above also be drawn to the attention of the Commission's DPP5 work programme, which Ben Woodham described to me in his email of 25 May 2026 as covering incentive settings more broadly. I recognise that the specific mechanism fix requested in Section 4 extends beyond what the Ōpōtiki reopener decision alone can resolve; I raise it here because Ōpōtiki and Kope are, in my submission, two live illustrations of the same national pattern, and because live decisions - including the Whakatāne Museum inverter specification referred to in Section 3 - are being made in real time while the underlying settings remain unresolved.

I am happy to provide the underlying modelling referred to in Section 3, or to discuss any of the above further, at the Commission's convenience.

Graeme Weston

HEDL Consumer, Ōhope, Eastern Bay of Plenty

[redacted]