By email: [redacted]
30th September 2026

Submission on improving the efficiency of electricity distribution businesses

SUPA Community Energy (SUPA) considers it timely that MBIE is reviewing how the regulatory and governance framework for electricity distribution networks should be updated to ensure the large investments required for electrification are delivered efficiently, including that the right investments are made at the right time and in the right places. This is critical for helping to limit future increases in electricity prices while maintaining reliability and resilience.

EDBs (and Transpower) need to adapt and change in response to the energy transition. Managing electricity networks is becoming much more complicated, with more two-way electricity flows as consumers increasingly generate power as well as consume electricity from the grid. Our experience accords with the observations in the consultation that different EDBs have different capabilities and are making the necessary changes at different speeds. While this is inevitable to a certain degree, it will be important to ensure all EDBs have the capability and capacity to change and can, at the very least, be 'fast followers'.

SUPA's central submission is that the current framework does not consistently produce efficient outcomes because batteries and other flexible resources are often unable to compete fairly with traditional network investment. SUPA supports:

- greater regulatory scrutiny of electricity distribution network investment;
- initiatives aimed at encouraging and supporting greater use of non-network solutions; and
- collaboration and standardisation, including in relation to electricity network pricing (including transmission cost pass-through) and a national flexible load and battery access (and network pricing) framework.

Responses to selected consultation questions are provided in the Appendix to this submission.

Executive Summary

As New Zealand electrifies, consumers will fund substantial network investment through their electricity bills. The regulatory framework should therefore ensure that every investment is the lowest-cost solution available. At present, batteries and other flexible resources are often unable to compete fairly with traditional network upgrades because network pricing, transmission cost pass-through, and regulatory incentives favour building network assets

rather than enabling non-network alternatives. MBIE, the Commerce Commission and the Electricity Authority should reform pricing, investment scrutiny and incentive settings so batteries, demand response and other flexible resources can compete on equal terms and help avoid or defer unnecessary network expenditure.

SUPA's central concern is that current distribution pricing and transmission cost pass-through can penalise batteries even when they charge off-peak, discharge on-peak, improve resilience, and help avoid or defer network investment. The issue for MBIE is whether the regulatory framework is delivering efficient investment signals. Current tariff structures, including anytime demand, contracted capacity and volumetric charges in some regions, illustrate how existing arrangements can create barriers to efficient battery investment. Inefficient network pricing practices have made otherwise efficient storage projects uneconomic and delayed SUPA's planned battery deployment. We would be happy to work through real-world examples with MBIE and/or the Commerce Commission and Electricity Authority.

This isn't just bad for SUPA. This matters because consumers ultimately fund network expenditure and therefore bear the cost of inefficient investment.

SUPA supports national standardisation of flexible load and battery access arrangements, while preserving locally appropriate prices and operating limits. WEL Networks' distributed generation (DG) process is an example of a process that works well. The Electricity Authority should be directed to work with the Commerce Commission, electricity networks, and stakeholders to deliver network pricing reform by 1 April 2028 at the latest, with a legislative backstop if progress is too slow or does not address the problem.

The regulatory framework should also test whether proposed network expenditure is the lowest cost way to meet consumer needs and give non-network alternatives a fair opportunity to compete before capital-intensive upgrades are locked in. Similarly, where non-network alternatives are being considered, EDBs should either outsource provision of these services or ensure that they have appropriate protocols in place, so in-house solutions and third-party options are considered on a competitively neutral and non-discriminatory basis. SUPA supports adoption of arm's-length rules and restrictions on use of information based on existing Part 6A Electricity Industry Participation Code precedent.

SUPA considers that existing Part 4 incentives do not always align network incentives with the lowest cost outcome for consumers, because network businesses can earn regulated returns from assets they own but not necessarily from third-party solutions they enable.

SUPA supports stronger regulatory scrutiny of distribution investment, including enhanced Information Disclosure and developing an electricity distribution Capital Expenditure Input Methodology (Capex IM). Significant network investments should include a documented assessment of potential non-network alternatives. The assessments should take into account the time to deployment of different solutions. Non-network solutions (batteries) can usually be deployed far quicker than network asset investments.

SUPA considers that price-quality regulation should be applied to all EDBs. SUPA similarly supports extending Individual Price-Quality Paths (IPPs) to larger EDBs because the scale of future expenditure associated with electrification increases the value of project-by-project scrutiny. As investment requirements grow, consumers would benefit from greater assurance that major projects represent the most efficient long-term solution.

Summary of Recommendations

1. Strengthen investment scrutiny
    - Extend IPPs to larger EDBs/remove small EDB exempt status.
    - Require development of a distribution Capex IM.
    - Require assessment of non-network alternatives.
2. Align incentives
    - Review Part 4 incentives to ensure EDBs are rewarded for lowest cost outcomes rather than asset ownership.
3. Reform pricing and access
    - Reform network (distribution + transmission) pricing and transmission pass-through.
    - Establish a national flexible load and battery access framework by 1 April 2028.
    - Introduce a legislative backstop if reform does not progress.
4. Improve accountability
    - Expand monitoring and reporting, including reporting on EDB use of non-network alternatives and treatment of third-party providers.
5. Regulate ancillary and non-network solution activities
    - Adopt arm's-length rules and restrictions on use of information for EDBs that adopt their own in-house provision of non-network alternatives.
    - Introduce a legislative backstop in case reform does not progress adequately.

Not everything that SUPA considers should be done will necessarily require legislative change, but it will require regulatory cooperation and coordination amongst regulatory agencies given their overlapping powers and responsibilities. In short, SUPA's submission asks the Electricity

Authority to fix pricing and access rules, the Commerce Commission to fix investment incentives, and MBIE to ensure both reforms happen and are completed on time.

Agency	Division of responsibilities
Electricity Authority	Fix network pricing and access rules.
Commerce Commission	Fix investment incentives and strengthen expenditure scrutiny.
MBIE	Set the policy direction, require reform, and provide legislative backstops if regulators do not deliver.

SUPA supports the MBIE positioning on network pricing

The discussion document already describes the outcome. In an efficient system, "price frameworks are consistent across the country, and price signals are clear, optimised for each network's conditions, and sufficiently flexible to differentiate signals for localised areas". Networks should be "procuring non-network solutions (such as batteries or demand flexibility) where this delivers cost-effective outcomes."

The Government wants "faster system change on issues such as pricing approaches".[1]

The June 2026 Government Policy Statement says efficient network pricing is essential "to find the lowest cost solution, which may include demand-side response and flexibility to avoid or defer the need for network capacity augmentation", and makes the Authority responsible for "setting principles (and regulating if warranted) for transmission and distribution pricing structures."[2]

The Policy Statement says demand-side response and flexible supply such as batteries "will become more valuable, particularly in managing demand peaks and periods when short-term capacity is tight."[3] If stored renewable energy competes to serve the peak, the price of peak energy falls, and so does the cost of the firming that retailers buy and pass on.

The Electricity Authority has described how more renewable generation pushes wholesale prices down, and said the key challenge is "ensuring that those reductions in generation costs flow through to households and businesses in a timely manner."[4] Storage is how cheap midday energy reaches the 6pm bill. It also adds competition when supply is tight.[5] Short duration batteries do not solve a dry year, but they do address the daily peaks that thermal plant is dispatched to cover.

[1] MBIE, Discussion document for improving the efficiency of electricity distribution businesses, 19 August 2026, printed pages 7 and 9 (efficient system; faster system change) and pages 22 to 23 (performance requirements and investment rules).
[2] Statement of Government Policy to the Electricity Authority under section 17 of the Electricity Industry Act 2010, June 2026, paragraphs 10, 11(d), 15 and 16(a).
[3] Statement of Government Policy to the Electricity Authority under section 17 of the Electricity Industry Act 2010, June 2026, paragraphs 10, 11(d), 15 and 16(a).
[4] Electricity Authority, Breaking the link between gas supply and power prices and what it means for New Zealand's energy future, 16 July 2026.
[5] Electricity Authority, Unlocking the potential for batteries to contribute to security of supply, 16 April 2024.

Network pricing is a critical area that needs to be fixed

We consider that there would be considerable benefit from more standardised and consistent network pricing (including transmission pass-through) to better ensure it encourages the efficient adoption of new technologies, including batteries, and supports delay or avoidance of costly (distribution and transmission) network upgrades.

We are concerned network pricing reform is too slow and may need some course corrections.[6] By way of example, the Electricity Authority wrote an open letter to electricity distributors in 2022 detailing, among other things, that it did not consider Anytime Maximum Demand (AMD) pricing to be appropriate in any circumstances and said it should be removed "as soon as possible", but such practices persist four years later.[7] Distribution tariffs that charge a site for its anytime maximum demand, its contracted capacity, or a flat rate on every unit it imports, can inefficiently price batteries out of New Zealand's networks.[8]

The Electricity Authority's recent work on distribution pricing also appears to have become bogged down in contentious debates over cost allocation between different customers, including with the introduction of "neutral" and "balance" points.

SUPA considers that greater priority should be given to improving the efficiency of network pricing signals and removing barriers to flexible resources such as batteries. This is not simply a pricing issue. It is an investment efficiency issue. Tariffs that discourage batteries increase the likelihood that networks will need to recover the cost of future augmentation from consumers through regulated expenditure.

The problem: anytime charges price batteries out

Many networks charge larger sites for their anytime maximum demand or contracted capacity and add a flat charge to every unit imported. These charges do not take account of when the demand occurs. A battery charging at 3am can pay the same for its kilowatts as a factory running at 6pm. A flat usage charge adds the same network cost to every unit, whether the network is empty or running at full capacity. That harms the economics of battery storage even when it avoids every period that drives network investment.

Case Study: North Island network

In August 2026, a large North Island network prepared an illustration for SUPA of the lines charges for a 900 kW / 1,800 kWh battery charging 657 MWh a year, one full cycle a day.[9]

[6] For example, SUPA and many other stakeholders have raised concerns with the Electricity Authority about the transmission pricing methodology (TPM) and the missing dynamically efficient peak signal: https://www.ea.govt.nz/documents/10233/SUPA_Energy.pdf.
[7] The Authority was very clear that "we query whether setting an individual customer's charges based on that customer's own AMD is useful in any circumstances, given it is likely to over-signal, and does not link well to the drivers of network cost" and "We expect distributors to reduce their use of charges based on a customer's own AMD as soon as possible and have a clear roadmap for removal of such misaligned charges." [emphasis added]
[8] Anytime demand and capacity charges and flat usage charges should go. In their place: a low or zero charge when the network has capacity, a strong published price at the network's peak, and a fair contribution to shared costs. Prices and operating limits should be set locally. The framework should be national.
[9] Illustrative lines charge calculation prepared for SUPA by a large North Island distribution network, August 2026. Both cases assume 657 MWh of charging a year and no peak coincident demand charge. Available to MBIE on request.

Charging over two hours each night, the estimated annual lines charges were about $155,000. Spread over eight hours, about $55,000. Neither case included a peak coincident demand charge. Per unit stored, that is about $236 per MWh at two hours and $84 per MWh at eight. Almost all of the difference came from the battery's own maximum demand.

These were illustrative calculations, not bills, and they do not prove spare capacity at every location and hour. But they show the point. The tariff charged the battery for the size of its charger, not for what it did to the network.

The eight-hour case is not the answer either. Eight hours of charging leaves no room for a second cycle from midday solar into the evening peak, and no room to charge when the wholesale market is cheapest. Even at eight hours, $84 per MWh of network charges is added to every unit stored, on top of the energy itself, before the battery earns anything.

The effect on SUPA is direct.

Around 20 MWh of battery storage in our plans has not been built because line charges are misaligned with how our batteries charge and discharge, making those projects commercially unviable. Across the 22 networks presently in our pipeline,[10] none of them publishes a tariff that a battery can qualify for based on how they operate. Where we have secured workable pricing, it has taken months of negotiation for each site, with the outcome depending on the network. From the customer's perspective, this is one of the barriers to standardisation that the consultation asks about.

The Electricity Authority's own guidance already says these practices should not be happening. Its Distribution Pricing Practice Note explains that residual costs, the costs left after the price signal has done its work, should be recovered in a way that gives a customer "no reason to change their electricity consumption use or pattern". It then warns that "residual cost allocation should never be updated regularly based on a customer's anytime maximum demand in each period. That would create a strong inefficient price signal and seriously distort consumer demand."[11] That is exactly what anytime demand and capacity charges do to a battery. Recovering residual costs is necessary. The method matters.

Who pays when the battery is not built

Adding batteries to an electricity network provides multiple benefits.

Batteries can improve network resilience, help spread the recovery of fixed network costs, and reduce or delay the need for network upgrades. Batteries that charge off-peak and discharge on-peak flatten the network's load. Battery storage is one example of the non-network solutions contemplated by the discussion document.

[10] There are presently 6 smaller EDB networks that we have not entered.
[11] Electricity Authority, Distribution Pricing Practice Note, second edition v2.2, October 2022, paragraphs 114 to 119 (residual cost recovery) and paragraphs 12 to 13 (revenue caps).

More efficient utilisation of existing network capacity, including through battery storage and usage, reduces future cost pressures on electricity bills.

The Commerce Commission's recent open letter makes similar observations, emphasising the importance of "making the most out of existing assets by avoiding premature replacement or upgrades" and noting that "Nor should consumers be disadvantaged by a failure to effectively use the flexibility associated with consumer loads/resources such as EV charging that can be orchestrated through cohesive pricing and contracting approaches."

The benefits beyond the network

New Zealand's peaks are increasingly served by imported fuel. Domestic gas is declining.[12] Much of Huntly's coal is imported. The Government Policy Statement says the Government is looking to establish an LNG import terminal to provide a reliable backup fuel source.[13] When the plant at the margin is burning imported fuel, every megawatt hour of peak demand met from a battery charged on New Zealand wind, water and sun is fuel not bought offshore. As transport and process heat electrify, the peaks grow and so does that saving. Storage that shifts our own renewable energy into the peak is a direct contribution to New Zealand's current account, and it compounds as electrification accelerates.

Inefficient pass-through of transmission charges

Transpower's Grid Pricing team confirmed in writing to SUPA on 4 September 2026 that "only battery losses are included in residual charging, regardless of whether the battery is grid-connected or embedded within an EDB", and that this applies to batteries of all sizes.[14]

Transpower also confirmed that each network's residual charge baseline is fixed and is adjusted using lagged data. The data used for the 2026/27 pricing year runs from 1 July 2018 to 30 June 2022. So, a battery commissioned today has no effect on its host network's transmission residual charge for several years, and when it does, only its losses count. The Authority's 2022 TPM decision recognised that failing to identify battery flows "may inefficiently discourage investment in batteries".[15]

The problem is what happens next. As Transpower put it, "EDBs have their own pricing methodology in allocating charges to their customers." Networks commonly pass transmission costs through to sites on an anytime demand or flat energy (variable) basis. A battery that avoids the network's peaks can then be charged for transmission costs that Transpower has not levied on the network for it. That is not a Transpower issue. It is a distribution pricing issue, and it belongs inside the same framework.

---

[12] Electricity Authority, Breaking the link between gas supply and power prices and what it means for New Zealand's energy future, 16 July 2026.
[13] Statement of Government Policy to the Electricity Authority under section 17 of the Electricity Industry Act 2010, June 2026, paragraphs 10, 11(d), 15 and 16(a).
[14] Transpower Customer Solutions, written response to SUPA on behalf of the Grid Pricing team, 4 September 2026. See also Transpower, Battery owner's guide to the TPM, and Electricity Industry Participation Code, Schedule 12.4, clauses 4(2), 4(3) and 4(7).
[15] Electricity Authority, 2022 TPM Decision, paragraphs 7.66 to 7.69, printed pages 55 to 56.

The framework should set a common process: half-hourly battery data from a dedicated ICP or equivalent metering, supplied by the network to Transpower, and pass-through that follows the treatment in the TPM. Transpower has told us there is no time constraint on supplying that data because of the lag. There is no reason to have 28 different answers.

Opportunities for non-traditional solutions as part of the energy transition

SUPA is excited about the opportunities that exist for non-traditional solutions to provide lower cost and more efficient solutions to electricity network requirements. Electricity distributors are going through a transitional phase and are exploring the most effective ways to integrate flexibility services, DG, and consumer participation into their networks.

The value proposition we offer started with opportunities to benefit from intraday price volatility and is evolving to use batteries with solar to provide distributors with non-network alternatives.

SUPA encourages the integration of non-traditional solutions, such as batteries with solar, to provide distributors with non-network alternatives. The industry is in transition, and there are untapped opportunities for better utilisation of distributed energy resources.

From SUPA's perspective the industry is at an immature stage with a large number of untapped opportunities for better utilisation of distributed energy resources (DER). This isn't a criticism of the industry. It just reflects the reality that the industry is in a state of transition, and everyone is on a learning curve.

Inevitably some electricity distributors will be faster to adapt, and this will provide a pathway for other distributors to see the potential benefits of alternative solutions and to be fast followers.

Regulation of ancillary investments

SUPA considers that application of price-quality regulation for all EDBs would protect consumers from bad investments in unregulated activities.

If an EDB makes a bad investment in a winery, that should be a hit on shareholder returns, not an impost on consumers through higher line charges.

Our understanding of the Local Government (Water Services) Act 2025 precedent MBIE is considering is that these provisions are principally aimed at ensuring water suppliers have the financial wherewithal to make the necessary investments in their water infrastructure, and to ensure limited resources are not diverted to other council activities. That is a different problem from protecting consumers or ensuring investments in unregulated activities do not have a harmful impact on competition.

We would be happy to share some of our experiences with MBIE (and other regulators), but our concern is with the impact of the inherent conflict where an EDB should be considering third-party outsourcing of non-network solutions but may also be considering in-house solutions.

We consider that clear protocols are needed to ensure: (i) EDBs select the lowest cost and most efficient solution, rather than preferring its own in-house solution or business; and (ii) commercial information provided by potential third-party suppliers is used to evaluate the third-party options but cannot be shared with or used by the in-house business to develop its own solution.

This may require development of or extension to existing arm's-length rules and restrictions on use of information to apply to non-network solutions in Part 6A of the Electricity Industry Participation Code/previously in the Electricity Industry Act.

Again, we consider that this is something the Electricity Authority should be directed to consider and, if adequate progress is not made, the Government should have backstop regulatory powers to introduce its own requirements. We consider that it should be a straightforward matter to address based on existing precedent.

Fix the incentive: let networks earn from enabling storage

MBIE should consider whether Part 4 regulatory settings provide sufficient incentives for EDBs to prefer the lowest cost solution to consumers, regardless of whether that solution is network investment or a third-party non-network alternative.

This issue is central to the consultation because it goes directly to whether existing regulatory settings consistently deliver the lowest cost outcome for consumers.

Under price-quality regulation, a network earns its return on its regulated asset base. Building lines grows the base. Enabling someone else's battery does not. A tariff that brings a battery onto the network adds revenue that washes up and an avoided feeder that never enters the asset base. For a network with private shareholders, that is a direct conflict between what is good for consumers and what is good for the business. MBIE's Cabinet paper acknowledges the conflicting incentives networks face in implementing change.[16] This is perhaps the clearest example.

The Commission has done useful work. It set the capex retention rate equal to the opex rate to remove the bias between them, and the innovation allowance funds trials, including up to $8.36 million for Powerco's distribution system operator programme.[17,18] Those measures reduce the bias against operating spend and pay for learning. They do not give a network a reason to prefer a battery on a tariff over a new feeder.

[16] Cabinet paper, Actions to improve performance of electricity distribution networks and release of discussion document, 28 August 2026.
[17] Commerce Commission, DPP4 final decision, Attachment D: Innovation and section 54Q incentives, 16 December 2024, pages 2 to 5 (capex retention factor set equal to the opex rate; Innovation and Non-Traditional Solutions Allowance).
[18] Commerce Commission, Innovation project explores how electricity distributors can unlock more value, 31 August 2026 (up to $8.36 million of allowance for Powerco's distribution system operator programme).

Electricity network owners should be agnostic between electricity network investment and the adoption of non-traditional alternatives. Part 4 of the Commerce Act should incentivise and reward electricity networks for finding the most efficient solution.

One option that could be considered would be to allow electricity networks to keep a bounded share of the value they create by enabling storage and other distributed energy resources: for example, a share of demonstrated avoided or deferred capital expenditure, or of new tariff contributions, for a fixed period. This would need regulatory approval, evidence of additional value, protection against paying twice for the same benefit through existing incentives, and other consumers left better off. It should not become a condition for a project to qualify. For exempt networks, the equivalent question is how their owners measure success, and the same measure should apply.

This means letting networks make more money when they enable investment that lowers costs for everyone else. We think that is the right trade. The alternative is the current one, where the only way a network improves its own result is to build.

Concluding remarks and recommendations

Consumers will ultimately fund the network investment required for electrification. The issue is not whether electrification requires investment. The issue is whether the regulatory framework ensures consumers get the cheapest solution, regardless of whether that solution is a new network asset or a battery.

The objective of regulatory reform should therefore be to ensure that every dollar of network expenditure represents the lowest cost way of delivering reliable electricity services:

1. The regulatory framework should drive least cost electrification.

2. Non-network alternatives are not competing on equal terms.

3. Regulatory incentives favour building over enabling.

4. MBIE should strengthen investment scrutiny, monitoring and accountability.

5. Network pricing reform is necessary because it affects investment efficiency.

SUPA recommends that MBIE, the Electricity Authority and the Commerce Commission prioritise the following actions.

First, require that significant network expenditure is demonstrably the lowest cost option available to consumers after reasonable consideration of non-network alternatives.

There should be greater scrutiny of network investments, including through application of IPP provisions to larger EDBs and adoption of an electricity distribution Capex IM, similar to the

approach taken to Chorus and Transpower. The Commerce Commission should use Option 2A so that significant investments carry a documented assessment of non-network alternatives, including third-party batteries. The Commerce Commission should also ensure that networks have incentives to support third-party batteries and DER where this would be lower cost or more efficient than major capital expenditure.

Second, electricity network pricing, at both distribution and transmission levels, needs urgent reform. Network pricing needs to encourage batteries that charge off-peak and discharge during peaks. Clear peak-usage pricing, combined with low or nil off-peak pricing, should be adopted across the country at both the distribution and transmission levels. Anytime maximum demand pricing, contracted capacity charges and other pricing that penalises efficient off-peak grid use should be prohibited or phased out.

Third, the Electricity Authority should lead delivery of a national flexible load and battery access framework by 1 April 2028 at the latest, working with the Commerce Commission, electricity networks and other stakeholders. That framework should standardise application processes, metering requirements, and battery data treatment.

Fourth, this should include adoption of arm's-length rules and restrictions on use of information for EDBs that provide in-house non-network solutions to ensure these are not favoured at the expense of third-party options.

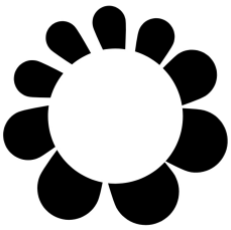
Fifth, if the Authority's programme does not deliver on time or does not resolve the barriers to batteries and efficient grid use, Government should have a backstop power to direct Code amendments on distributor pricing methodologies and access terms.

Consultation options	**SUPA view**
Collaboration and standardisation	SUPA supports a standardised approach to network (distribution and transmission) pricing and to flexible load and battery network access.
Expanded Monitoring (Options 1A and 1B)	SUPA supports publication of information demonstrating whether EDBs are enabling efficient use of batteries, demand response and other flexible resources. The Commerce Commission should publish periodic assessments of the extent to which EDBs are adopting non-network solutions and whether proposed expenditure could reasonably have been deferred or avoided through flexibility services, including reporting on: • non-network alternatives assessed; non-network alternatives procured; • batteries and flexible load connected; • application processing times; • reasons for refusal; and • estimated network expenditure avoided or deferred.

Consultation options	SUPA view
Option 2A	SUPA supports Option 2A because requiring assessment of non-network alternatives before significant expenditure improves confidence that network investment is the lowest cost option for consumers.
Option 2B	SUPA supports removal of the small EDB exemption status. We note that the exemptions were extremely controversial at the time they were introduced and opposed by the Commerce Commission.
Option 2C	SUPA supports application of IPPs for larger EDBs.
Option 3B	SUPA supports adoption of arm's length rules and restrictions on use of information in relation to EDB provision of non-network solutions.
Option 3C	SUPA supports governance expectations that ensure boards have capability in distributed energy resources, flexibility services and electrification.

Success should be measured by tariff availability on each network, application times, reasons for refusal, megawatts and megawatt hours enabled, actual operating behaviour and the effect on other consumers. Comparisons should allow for local conditions. Counting installed batteries alone would not tell anyone whether it is working. SUPA is willing to share its project data and modelling to help.

Yours sincerely,



Andy Cooper
CCO
SUPA Energy

m. [redacted]
e. [redacted]
w. www.supa.energy

Appendix: Responses to the consultation questions

Q1. How could regulatory settings better support standardisation and collaboration? SUPA supports a standardised approach to network (distribution and transmission) pricing and to flexible load and battery network access.

Electricity network pricing, at both distribution and transmission levels, needs urgent reform. Network pricing needs to encourage batteries that charge off-peak and discharge during peaks. Clear peak-usage pricing, combined with low or nil off-peak pricing, should be adopted across the country at both the distribution and transmission levels. Anytime maximum demand pricing, contracted capacity charges and other pricing that penalises efficient off-peak grid use should be prohibited or phased out.

The Electricity Authority should lead delivery of a national flexible load and battery access framework by 1 April 2028 at the latest, working with the Commerce Commission, electricity networks and other stakeholders. That framework should standardise application processes, metering requirements, and battery data treatment.

If the Authority's programme does not deliver on time or does not resolve the barriers to batteries and efficient grid use, Government should have a backstop power to direct Code amendments on distribution pricing methodologies and access terms.

Q2. What barriers are there? From the customer's perspective, 28 networks mean at least 28 tariff structures. Every viable site needs a bespoke negotiation taking months, and the same battery is viable in one network and not in the next. Networks also face the incentive problem: their return comes from assets they own, not from batteries they enable. Government action that would help includes direction and dates for the Authority, a backstop power, and an enablement incentive from the Commission.

Q3. What is the likely scale of benefits? For SUPA alone, around 20 MWh of battery storage in our plans has not been built because of inefficient line charges, out of a pipeline of around 90 sites. Each battery that is built pays network charges other consumers would otherwise carry, flattens local load, and moves renewable energy into the peak in place of imported fuel. The national scale should be measured through the framework. We would expect it to be a multiple of what any one developer sees.

Q4 to Q7. Monitoring. The chapter describes the current framework accurately, but that framework does not show whether networks enable efficient use of their assets by third parties. We support Option 1A, and Option 1B where proportionate. Published conclusions should include tariff availability, application times, refusal reasons, investment enabled and effects on other consumers, adjusted for local conditions. Existing information powers should be used where they suffice.

Q8. Does the chapter describe the current situation accurately? It describes the tools. It does not describe the incentive that sits underneath them: a return earned on owned assets

means building is rewarded and enabling is not. That is the reason non-network solutions are slow to arrive, and it should be named.

Q9. Options. SUPA supports the options outlined in this chapter. We support the performance requirements and investment rules in Option 2A, used to require assessment of non-network alternatives before significant investment. Whatever tools are chosen for exempt networks, the tariff framework itself must apply to all 28 networks.

Q12 to Q16. Governance. Board capability should include an understanding of distributed energy resources and electrification. The pricing and enablement expectations above should apply to all networks regardless of ownership. We take no position on ownership reviews and do not propose changing ownership as a condition of this work.

Q13 Regulation of ancillary services.

SUPA considers that application of price-quality regulation for all EDBs would protect consumers from bad investments in unregulated activities.

We would be happy to share some of our experiences with MBIE (and other regulators), but our concern is with the impact of the inherent conflict where an EDB should be considering third-party outsourcing of non-network solutions but may also be considering in-house solutions.

We also consider that, where an EDB is considering in-house options for non-network solutions, clear protocols are needed to ensure: (i) EDBs select the lowest cost and most efficient solution, rather than preferring its own in-house solution or business; and (ii) commercial information provided by potential third-party suppliers is used to evaluate the third-party options but cannot be shared with or used by the in-house business to develop its own solution.

This may require development of or extension to existing arm's-length rules and restrictions on use of information to apply to non-network solutions in Part 6A of the Electricity Industry Participation Code/previously in the Electricity Industry Act.

Again, we consider that this is something the Electricity Authority should be directed to consider and, if adequate progress is not made, the Government should have backstop regulatory powers to introduce its own requirements. We consider that this should be a straightforward matter to address based on existing precedent.