Margarita Parra
Ōtautahi - Christchurch

May 12, 2026

The Electricity Authority - Te Mana Hiko
Te Whanganui-a-Tara - Wellington
Via: distribution.pricing@ea.govt.nz

Kia ora,

I am grateful to the Electricity Authority for providing the opportunity to comment on the Consultation Paper: Reforming Network Pricing for Distributed Generation. I am a clean energy policy advocate with expertise in the integration of electric vehicles and other distributed energy resources into the grid, primarily in the U.S. I am currently a committee member of LETS — the Lyttelton Energy Transition Society — promoting community solar and other initiatives.

I concur with the fundamental premise of this reform: to facilitate the expansion of distributed generation (DG)—encompassing solar, residential battery storage, and bidirectional EVs, among other forms—integrated into distribution networks to ensure the most cost-effective outcomes for all consumers. This objective aligns with a broader, critical imperative for Aotearoa New Zealand, where DG can help mitigate electricity price surges that impact consumers and more vulnerable communities during this global energy crisis. I am pleased to offer the following responses to selected questions from the consultation.

Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?

Yes, I agree that this is appropriate. The Electricity Authority's proposal for Distributed Generation Pricing Principles (DGPPs) provides an accurate accounting of all costs and benefits associated with DG injection and establishes a fairer mechanism to allocate the *net benefits* (I use *net benefits* rather than *net costs*, as I believe there are overall more benefits than costs!) among distributed generators as well as the network's users. In addition, with the regulation, all EDBs will have the same guidance and can provide pricing consistently and transparently. This will spur more efficient deployment of DGs and reduce overall costs for all.

Through this proposed methodology, the Electricity Authority (EA) is addressing critical asymmetries inherent in the calculation of costs and benefits for DG, specifically regarding location and time. While costs for DG injection are often localised—where upgrades may be required only in specific segments of the distribution network or where restricted capacity exists elsewhere—the long-term benefits of DG injection are realised across the entire network. Further, while certain costs are discrete, one-time expenditures—such as substation upgrades, local transformer enhancements, or the deployment of optimisation software—the benefits accrue linearly; once integrated into the system, DG provides cumulative value.

Another piece of the regulation that will encourage more DG and distribute new incremental costs fairly is the pioneer scheme. This pioneer scheme and the rebate mechanism will address the “first mover” challenge when it comes to the need for capacity upgrades or maintenance. At the same time, even if implicit in the proposed methodology, it is important to emphasize the need to optimise the utilisation of existing network assets as the first measure to lower incremental and residual costs. I support the idea of residual costs being paid by all consumers, not the DG producers to level the plain field (equally the non-discrimination of DG ownership).

Even accounting for the new incremental costs of managing DG complexity—which requires more optimisation software to manage where and when injections are ideal among many users to avoid new peaks—in the long term, DG will provide more benefits and defer the need for new infrastructure and new capital assets. Those deferred investments will be impactful for all electricity payers. There is substantial evidence of this. In the U.S., back in 2021, the Lawrence Berkeley National Lab[1] studied 24 power utilities with DG programs and found that these programs, in fact, defer investments in distribution feeders, substations, transformers, and even transmission upgrades. One important finding is that DG has the highest benefit when targeted to specific constrained locations. A more recent study by the Pew Charitable Trust[2] found that fully leveraging DGs with smart software, including providing appropriate compensation for DG owners, could deliver power during peak demand at 40%-60% of the cost of traditional solutions.

Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing is appropriate at this stage? Why?

I understand the need to provide flexibility in how each distributor (EDB) applies the DGPPs given different baselines. At the same time, given the urgent need to reduce costs overall and the fact that the New Zealand system has two regulatory agencies (the Electricity Authority—EA, and the Commerce Commission—CC), it is important to cross-reference and ensure consistency (beyond what is presented in sections B32 - 39).

The existing EA regulations already specify that EDBs (as of April 1st, 2026)[3] have to include negative tariffs to consumers (residential and small business) for injecting electricity into the network at peak times. As a consequence, there will be avoided costs or deferrals of capital investments given the DG benefits shown before. At the same time, the CC requires EDBs to provide forecasts of their capital investments through Asset Management Plans (AMPs) which includes non-network solutions and DGs. Only some of these include material impacts from DG (there is no standard methodology, so some EDBs are leaders while others are lagging).

There is a clear link and interdependence between the impact of the new principles for pricing DG and the contents of the AMP. If there are not enough price signals (perhaps derived from non-prescriptive application of the DGPP) or incentives, there will not be enough deployment of DGs, and there will not be enough cumulative benefits for deferrals in costly infrastructure (long-term flexibility and low-cost generation), which will impact assets under the AMPs.

---

[1] Berkeley Lab. Locational Value of Distributed Energy Resources. 2021
https://eta-publications.lbl.gov/publications/locational-value-distributed-energy

[2] Pew Charitable Trust. Distributed Energy Resources Can Unleash the Resilient Affordable Grid of the Future. 2025.
https://www.pew.org/en/research-and-analysis/reports/2026/04/distributed-energy-can-unleash-the-resilient-affordable-grid-of-the-future

[3] Electricity Authority. Distribution Pricing: Practice Note Second Edition v2.2, 2022
https://www.ea.govt.nz/documents/8429/2A_Final_Negative_Charge_Guidance_Document_for_Distributors.pdf

To avoid the “chicken and egg” situation with DGs and their benefits to the grid, my suggestion is that there should be a clearer cross-reference between what the EA and CC regulate. Ideally, EDBs could set targets in their AMPs, directed by the DGPPs toward achieving any of these related outcomes:

- X% of DG penetration by service area / feeder / substation, with a localised assessment as some areas may benefit more.
- Y% higher utilisation of assets with DG in areas where there is a greater need to reduce network costs.
- Z% higher affordability and cost reductions with DG in the long term for everyone.

The methodologies for calculating and reporting these outcomes are available and should be used consistently across EDBs in both AMPs and DGPP-reported pricing methodologies. The targets (X, Y, and Z) for each region can depend on the baseline of each EDB and its respective current priorities (i.e., reliability, resilience, efficiency or improving economic outcomes & reducing congestion). Distributors should demonstrate how they are planning to achieve the outcomes with price signals and other incentives and what the resulting cost avoidance is. I should note that I applaud the recent joint letter to EDBs by the EA, EECA, and CC[4]. It is a good start for incorporating DGs into grid planning but, in my opinion, it needs more regulatory force with clear outcomes as suggested above.

Q14. Do you have any suggestions for how we can most effectively support successful implementation?

One way to support the implementation of these principles could be found in a recent new approach: **proactive grid planning**. The Electric Power Research Institute (EPRI) in the U.S. started to lead a proactive grid-build approach to prepare for rapid DG deployment, focusing on anticipating future load growth—rather than reacting to it—to ensure capacity and reliability. They have developed specific tools to anticipate DG growth, especially around EVs[5]. Some State Commissions in the U.S. have started to implement a proactive planning approach through formal proceedings. In 2025, New York was the first state to publish an Order to Adopt a Modified Proactive Planning Growth.[6] Other states, such as Minnesota and California, are following and some are specializing in particular segments as EVs or in rural electric distributors.[7] As summarized by the Environmental Defense Fund[8], the proactive approach for grid planning follows these main steps:

---

[4] Joint Open Letter to Distributors for Efficient Solutions to Growing Networks. 2026 https://www.ea.govt.nz/news/general-news/joint-open-letter-calls-for-efficient-solutions-to-growing-networks/

[5] EPRI EVs2Scale and GRIDReady tools https://msites.epri.com/evs2scale2030

[6] State of New York Public Service Commission. Case 24-E-0364. In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure. 2025. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80185E99-0000-CF1D-A57E-F4A6874B79D5}

[7] In 2025 along with colleagues of the Environmental Defense Council I published at the magazine Public Utilities Fortnightly a paper exploring proactive grid planning for heavy duty electric vehicles by small rural distributors. https://www.fortnightly.com/fortnightly/2025/10/electric-trucks-and-buses-rural-co-ops

[8] Environmental Defense Fund. New Yorks New Grid Planning Framework Looks to Meet Growing Energy Demand. 2025. https://blogs.edf.org/energyexchange/2025/09/19/new-yorks-new-grid-planning-framework-looks-to-meet-growing-energy-demand/

1. Develop granular bottom-up load forecasts that identify electric load "hot spots" where demand is likely to increase the most;
2. Employ long-term forecasting to help "right-size" investments and minimize inefficient, incremental projects;
3. Consider distributed generation and grid-enhancing technologies—which can often be cheaper than traditional utility infrastructure—as part of the solution.

Some EDBs are already involved in No. 1: a bottom-up load forecast. I note my own network, Orion, published their AMP update as a consultation last year[9] (although I did not see it in time to participate). The document does not yet have a dedicated section about DG or how DG can be an alternative (No. 3), but it could. The proactive approach aims at reducing the risk of overbuilding or underbuilding costly infrastructure.

There is already growing awareness about the importance of DG in New Zealand. Groups like the Lyttelton Energy Transition Society (LETS)[10], with which I am a committee member, are part of a growing ecosystem and are catalyzing community solar initiatives. There is interest in residential solar and EV adoption, which has increased given the global energy crisis. Further, there is interest in local energy exchange among community projects and neighbors with DG for energy resilience, independence, and affordability. By collaborating with entities like LETS, EDBs can adopt a more proactive grid planning approach that optimizes the utilization of existing assets and anticipates infrastructure requirements to avoid costly upgrades. Ultimately, leveraging DG in our communities will deliver impactful cost reductions for all electricity payers, including those for whom DG remains financially inaccessible.

Final consideration

The transition toward a more affordable and equitable grid is a critical imperative for Aotearoa New Zealand, and distributed generation is a vital component of this evolution. I believe the proposed DGPP reform represents a significant step toward that future, and I hope these suggestions assist in further refining the principles to achieve the impactful outcomes the Authority seeks.

Ngā mihi nui,
Margarita Parra

[9] Orion. Investing in the Future of Our Local Electricity Network. 2025. https://www.oriongroup.co.nz/assets/Our-story/Publications/Orion-AMP-2025.pdf
[10] Lyttelton Energy Transition Society - LETS. https://www.lets.org.nz/