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Submissions
Electricity Authority
PO Box 10041
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by email: distribution.pricing@ea.govt.nz
(subject line "Consultation Paper—distribution injection pricing")

Submission on -
Reforming network pricing for distributed generation to promote efficient investment

Thank you for the opportunity to provide feedback on the Electricity Authority's (Authority) consultation paper, *Reforming network pricing for distributed generation to promote efficient investment*, issued on 2 April 2026.

These issues are of significant importance to EA Networks and our customers. We are at the forefront of hosting distributed generation in New Zealand, with substantial existing hydro generation, one of the country's largest operating grid-scale solar farms, and a further three solar developments of approximately 30 MW each currently in progress.

At times, embedded generation on our network exceeds total local demand, resulting in exports to the grid. Several areas of our network are already injection-constrained, and we are actively developing congestion management solutions to accommodate additional generation. We are also working with new connection applicants to provide flexible access arrangements, including options where generation may be curtailed during peak injection periods. In some areas, we are managing the mandated pioneer scheme for generation and seeking transfer payments for connection of small-scale generation.

This letter sets out key elements of our response, and the appendix provides responses to the Authority's specific questions.

Capacity costing

We strongly support the inclusion of capacity costing in the assessment of incremental cost, and we support the flexibility to implement this in different ways - whether when capacity is added (the current approach), as capacity is consumed, or through congestion-based pricing.

As we have previously submitted, we see our service evolving into an interconnection service, used by and sized for both offtake and injection customers. In some parts of our network, injection has clearly become the binding constraint. In these areas, load has effectively assumed the position that injection once held, where the marginal cost to serve is close to zero.

In this context, it is difficult to justify that load customers continue to bear the full burden of residual costs and overheads. We are therefore disappointed that the proposed reforms do not go further to address this inequity. However, we acknowledge that the proposed shift to include existing hosting capacity within the definition of incremental cost represents a meaningful step in the right direction.

The flexible approach to capacity costing is important to us. The current regulations have required us to allocate hosting capacity for free, on a first come-first served basis. In areas of our network, this has consumed all available hosting capacity, and we have not been able to progressively share the cost of the next increment of capacity – we are pushed hard up against the “last straw” problem identified in the Consultation paper. In these areas, it is important that we can pivot to allocating capacity costs through lines charges, so that we can continue to enhance our service to accommodate future customer demands. In other areas (and for other distributors), a connection charge approach may provide a better solution for sharing capacity costs as the hosting capacity is consumed.

Anchor point approach

We support the shift away from requiring that charges “must not exceed” incremental cost. This cap effectively ensured that charges fell at an inefficient level *below* incremental cost, where existing customers are subsidising injection customers.

However, the proposed “anchor point” and estimation approach still provides for outcomes where charges will inefficiently fall below incremental cost.

While pricing below incremental cost results in inefficient outcomes, pricing above incremental cost (the neutral point) does not necessarily do so. Pricing above incremental cost and up to the “balance point” improves equity between customer groups, and ensures that each group benefits from the existence of the other. Inefficiency only occurs where the access seeker is turned away by the higher costs, and often this will not occur right through to the stand-alone costs (which might pragmatically be a direct connection to the grid).

We submit that the Code should support an approach whereby incremental cost is taken as a minimum level that should be charged, rather than as an anchor point.

Security levels

We design and build our network to meet customers’ needs. For the vast majority of our load customers, the value impact of an outage far exceeds the delivered cost of electricity. Acknowledging this, we design to a security standard that includes redundant assets and surplus capacity that helps us avoid or minimise the impact of outages.

This approach lends itself to congestion charging, where we can influence efficient customer behaviour through pricing, and a peak load that exceeds the secured capacity of the network is taken as a collective customer signal to enhance capacity (including through seeking flexibility services) – and in the meantime, the peak load is accommodated by the security capacity.

Injection customers are different. For this group, the value of an outage is usually directly tied to the prevailing energy price, with no premium. Capacity solutions for this group are effectively provided with no back up (which we refer to as N security), where a fault or failure results in an outage that continues until repairs are affected.

Put another way, injecting customers seek to use all the available hosting capacity in the network. In these situations, congestion charging is problematic, because a peak load that occurs despite the charging (signalling a willingness to pay for additional capacity) will trigger protection equipment that shuts of the supply for both load and generation customers.

The N-security approach also means that capacity sharing between load and injecting customers should not be taken based on a simple assessment of MW demand. For example, a zone substation designed to host 20MW of load, will be able to host 40MW of generation.

We think this difference should be recognised throughout the pricing principles, and in particular, in the application of congestion charging and pioneer schemes.

Congestion pricing

Congestion charging allows customers to make an explicit cost–service trade-off. Where the value of the service exceeds the congestion charge, customers can choose to continue; where it does not, they can curtail. When set appropriately, congestion pricing places decisions about demand for service in the hands of customers. Peak demand that persists despite congestion charges provides a clear signal that additional capacity may be warranted, including through non-network solutions.

However, congestion pricing relies on a diversity of customer responses, where some users are willing to curtail ahead of others. This diversity enables peak demand to be smoothed and allows available capacity to be utilised by those with the highest willingness to pay.

In contrast to our highly diverse load customers, our injecting customers are currently relatively uniform. They are almost exclusively renewable generators, with limited variation in input cost structures, and the majority have little ability to defer production (for example, solar generation without storage and run-of-river hydro).

This lack of diversity makes setting an effective congestion price challenging. If the charge is set below the prevailing energy price, most or all generators are likely to continue injecting. Conversely, if it is set above the energy price, widespread curtailment is likely, resulting in underutilised capacity.

We think that while congestion charging for injection may be more effective in future, it may not provide an effective tool in the shorter term.

Timeframe for reform

These are complex issues and the solutions have real value impacts for customers, and can come with unintended consequences. The changes are significant, and much of the proposal covers new ground, that we have not previously considered.

The Authority's previous consultation (Distributed Generation Pricing Principles Issues paper dated 12 February 2025) indicated a proposed shift away from incremental cost (and included the words "and may involve including greater flexibility by removing the incremental cost rule" in its executive summary). In contrast, the current consultation adjusts but firmly embeds the incremental cost approach.

We think that imposing a February 2027 implementation timeframe will lead to rushed, sub-optimal and diverse outcomes. Providing more time for collaborative development of solutions will provide better and more durable outcomes.

Thank you again for the opportunity to provide feedback. If you have any questions regarding these comments, please feel free to contact me on [redacted]

Yours sincerely

[redacted]

Appendix: Response to specific questions

Questions	Comments
Q1. Do you agree with the background and context summary above? Why? Is there additional background, evidence, or context relevant to the proposals in this paper?	We have been advocating for change to the distributed generation pricing principles for more than a decade. The issue has been on the Authority's work programme but has been repeatedly deferred. While we do not wish to see the reform rushed, we do not agree with the Authority's opening statement indicating that "*the principles have performed well enough for many years*". The issues that the current principles have driven are significant and will be difficult to unwind. We think it is important to carefully consider how the reform will affect customers in future and drive more equitable outcomes.
Q2. Do you agree there are workability challenges with defining incremental costs under the current DGPPs? Why, why not? Are there any additional challenges not discussed above?	Yes. The current requirement to consider the difference between costs with and without a generator effectively prevents us including the consumption of existing hosting capacity in incremental cost The current wording of the pricing principles requires us to consider each generator, which brings with it the concept of order-of-arrival, and makes it difficult to assign costs that occur due to the collective addition of generation. The current requirements do not clearly set out how incremental costs can be assessed post connection. We have been challenged in relation to upgrades where the need becomes apparent after connection, and in relation to issues like harmonic mitigation, and where costs should fall when an incremental asset that has been incorporated into the network needs to be replaced.

Questions	Comments
Q3. Do you agree the current DGPPs cause costs and benefits to be under-allocated to injection connections, which can cause the issues listed above? Why?	Yes. The current requirements act to cap charges at incremental cost, and exclude consumption of existing capacity (which is widely recognised as an incremental cost). They also make it difficult to assign costs that arise due to collective generation. Costs of operating and maintaining the network, and administration of contracts and pricing, are all increased through the inclusion of generation. These additional costs are difficult to separately quantify, and while they can be estimated, the current requirement to wash up (recover or refund) any difference after the costs are incurred generally makes application unworkable.
Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?	We support the application of a principles-based approach to regulation of injection pricing methodologies.
Q5. Do you consider that consumers should remain residual payers? Why? Are there any additional economic concepts that should be considered in our reform of the DGPPs?	No. As noted in our cover letter and previous submissions, we think that our service is evolving into an interconnection service. All customers should share in residual costs, and all customers should benefit from the presence of other customer groups.
Q6. Do you consider that reframing the incremental cost rule to a requirement that charges 'must reflect a reasonable estimate of' rather than 'must not exceed' incremental costs is appropriate? Why?	Yes, but we think the reform should go further. "A reasonable estimate of" still allows for outcomes that fall below incremental cost, and this has inefficient outcomes as a vast pool of offtake customers must support a cross-subsidy, and some will efficiently decide not to consume. In the absence of sharing all costs (including residual costs), we support reform that sets the incremental cost as a minimum, rather than as a target or anchor. Please also see our comments in our cover letter.

Questions	Comments
Q7. Do you consider that the proposed amendments to language and framing would support more efficient pricing? Why?	No comment, other than a minor technical suggestion - clause 2(h) should be amended to align with the mandated provisions in the DDA (provide 40 business day's notice for increases).
Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing is appropriate at this stage? Why?	Yes. circumstances vary by location and between distributors. Please see the comments in our cover letter.

Questions	Comments
Q9. Do you consider that the proposed extension of the pioneer scheme for load connections would help address position-in-queue issues for injection connections? Why?	We are concerned about the cross-over between offtake and injection pioneer schemes. Recent generation customers have accessed existing hosting capacity paid for by past load customers for free. It would be incongruous for us to apply a scheme where the load hosting capability of an upgrade paid for by a generator resulted in a requirement for a pioneer contribution from a load customer. We are also concerned about the durability of pioneer schemes, particularly when injection is introduced. Distribution constraints are not static. As multiple layers of subsequent customers connect, system behaviour becomes highly state-dependent: • constraints vary with load and embedded generation output; • load reduces when customers serve on-site load with generation (this is generation that we can't dynamically manage, and it may ultimately eliminate the majority of load); • weather conditions drive coincident demand and generation; and • constraints shift over time and location across the network. In this environment, a simple "pioneer repayment" overlay is no longer sufficient to deliver outcomes that are fair, predictable, or administrable. It becomes increasingly difficult to clearly define, evidence, and enforce the relationship between: 1. who paid, 2. who benefits, and 3. who is curtailed, when, and why. Please also see the comments in our cover letter that reference the difference security provisions for load and generation. Pioneer schemes are a useful tool to address first-mover disadvantage. We think it may be appropriate to explore the option of keeping offtake and injection pioneer schemes separate (so that load customers only contribute to load pioneer schemes, and injection customers only contribute to injection pioneer schemes).

Questions	Comments
Q10. Do you consider that pioneer schemes should also cover network injection capacity? Why?	See above.
Q11. Do you consider that the proposed non-discriminatory pricing requirements would improve confidence that investors are safeguarded from discriminatory pricing? Why?	No comment.
Q12. Do you agree with the proposed application provisions, in particular with regard to opting out, retrospectivity and secondary networks? Why?	Opting out provides a generator with the option to contract for firm capacity, enter tripartite deeds with lenders, extend connection and commissioning deadlines, coordinate complex construction and commissioning processes and establish operational windows for things like voltage control, harmonic distortion, and reactive limits. In normal contractual negotiations, alternative approaches are settled through adjustment of price, and mandating a particular price can effectively prevent us from offering alternative solutions. We think it is important to maintain this option for our grid scale generation customers. Separately, we support the proposal to allow ongoing line charges to be modified for existing injection connections. While peak-injection constrained in many areas, our network can still host managed injection, and the proposed changes would allow us to share the costs of these enhancements.

Questions	Comments
Q13. Do you agree with the proposed commencement provisions above? Why?	EA Networks *is* experiencing injection congestion, and is currently issuing application approvals that include restrictions on output. Under the current framework, injecting customers have the option to fund additional capacity, or avoid using the network when it is constrained (through participating in a congestion management scheme). This approach encourages efficient use of the hosting capacity. Moving to a congestion charge approach to manage constrains is a very significant change, and provides a much less certain outcome. To ensure that the stability of the network is not compromised, it will need to be backed up with a congestion policy that mandates curtailment. As explained in our cover letter, unlike our very diverse load customers, where each will make a decision at a different price point, our injecting customers are very uniform. If a congestion price happens to be below the prevailing energy price at the time, all generators will elect to continue injecting. If it happens to be above the energy price at the time, all generators will curtail, and the capacity will be unutilised. We do not think that robust solutions can be developed and implemented in the timeframes the Authority is proposing.
Q14. Do you have any suggestions for how we can most effectively support successful implementation?	We recommend implementing a timetable, over a longer period, with milestones and steps to ensure progress. This will allow industry to collaborate and develop more robust and durable solutions.
Q15. Do you have any suggestions for effective monitoring and reporting, including proposed changes to charge reconciliation requirements?	Distributors have only just begun applying the new capacity costing methodology for offtake access seekers. We believe that there will be a range of learnings and improvements as this new approach is bedded in. A short delay in implement capacity costing for injection will allow the regulation to be informed by these learnings.

Questions	Comments
Q16. Do you agree it is appropriate to give distributors relatively wide discretion as to how they implement capacity charges for injection connections? Why?	Yes. In many areas, the current regulations have led to a situation where the existing hosting capacity for injection has been used up and distributors have been prevented from spreading capacity upgrade costs as that capacity was consumed. Given we have reached this point, it would not be appropriate to suddenly shift the responsibility for capacity upgrades on to distributors. To provide an example, our rural 54 MW Lauriston zone substation is injection constrained. Hosting another 100 kW generator during peak injection would require one of the transformers to be upgraded – very broadly, that upgrade would likely cost around $2m. It is important that distributors are give the flexibility to shift to a capacity costing approach in areas where they can accommodate that, but retain a last-straw approach in areas where they cannot.
Q17. Do you agree that for larger connections a more bespoke approach that accounts for dependability and mitigates risks such as over-injection or inefficient payments is more appropriate than the prescriptive broad-based approach used for residential and small business consumers? What do you consider such an approach should look like?	Yes – large customers meeting their own load is often sufficient to eliminate congestion in the local network. Rewarding generation over and above this, using a broad based pricing approach, risks inefficient spending that is ultimately funded by other customers. We think that a targeted opex approach (for example, through flexibility service providers) is a more efficient way to capture the benefits of load and generation response for larger customers.
Q18. Is there any specific guidance that would be particularly helpful for distributors implementing capacity charges for injection?	To address the legitimacy of approach and avoid disputes, while retaining a principles based approach with flexibility for distributors to address varied situations, we would like to see the Authority develop model approaches for congestion pricing and capacity costing.
Q19. Do you consider that inconsistent treatment of transmission connection charges for large generation projects may distort investment? Why?	We are concerned that the impact of distortions between embedded and grid connection may be overstated. There are a wide range of factors that affect the location and connection method for grid-scale generation. Embedded connections are usually substantially cheaper, and applying artificial adjustments (such as notional grid connection for assessment of benefit based charges under the TPM) may create more inefficiency than it solves.

Questions	Comments
Q20. Do you have a view on the best option to address the connection charge distortion issue? Please explain your rationale.	No comment
Q21. Do you consider that the restriction on recognising transmission benefits should be reconsidered if the other proposed Code amendments are made? Why?	There are a few aspects to consider here: • Under the current TPM, distributed generation has the effect of reducing exposure to new benefit based charges where these charges are established on a volume using a net load basis. • Separately, new large generation triggers an adjustment event which attracts additional benefit based charges for existing benefit based investments. Under the pricing principles, we pass on the increased cost associated with these adjustment events, but the requirements appear to prevent us passing on (or offsetting) the benefit of subsequent reduced exposure to future benefit based charges. • We note that there is a "generational" inequity in the TPM. Generators that were in place in the original reference period for benefit based charges **reduced** distributors' exposure to benefit based charges, yet through adjustment events, subsequent large generators **increase** distributors' exposure to benefit based charges. These factors will need to be carefully considered before any decision is made to recognise ACOT. The third point, in particular, will lead to some very large claims for payment from generators that were in place in the original assessment period.
Q22. Are there any other matters that you consider important for us to take into account in our reform of the DGPPs?	In the timeframe available, and with the new material and concepts, we have not been able to develop proposals for further or alternative reform. We have set out several matters in our cover letter and in answers to the questions above that we think should be taken into account.

Questions	Comments
Q23. Do you have any comments on the consumer impact analysis methodology or findings?	No comment.
Q24. Do you agree with the objectives of the proposed amendment? If not, why not?	We have not reviewed the regulatory statement.
Q25. Do you agree the benefits of the proposed amendments would outweigh the costs?	We have not reviewed the cost benefit analysis.
Q26. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	As noted above, we consider that our service is evolving to be an interconnection service. On this basis we think the alternative option "c" would have merit, where injection and offtake are priced consistently. The proposed solution is a step in this direction.
Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	No comment
Q28. Do you consider that the Authority's preferred high-level settings for injection pricing are consistent with the distribution pricing principles? Why?	No comment
Q29. Do you consider that consolidating distribution pricing methodology requirements into Part 6B would improve clarity and consistency? If not, why?	Yes
Q30. Do you have any comments on the drafting of the proposed amendment?	We have not comprehensively reviewed the Code amendment.