

19 May 2026

Networks and System Change Team
Electricity Authority
By email: distribution.pricing@ea.govt.nz

Tēnā koe,

Distributed Generation Pricing Principles – Consultation Paper

We welcome the opportunity to respond to the Electricity Authority (**Authority**)'s consultation paper *Reforming network pricing for distributed generation*.

Powerco is one of Aotearoa's largest gas and electricity distributors, supplying around 360,000 electricity and 114,000 gas connections to urban and rural homes and businesses across the North Island. Our energy networks provide essential services and will be core to New Zealand achieving a net-zero economy in 2050. We support regulatory interventions that assist the energy transition and protect customers across New Zealand.

Decarbonisation through electrification is important and urgent. The problem that justifies reform is not about efficiency alone, but about enabling a least-cost, equitable energy transition in the most efficient way possible. We welcome the Authority's proposals to update the Distributed Generation Pricing Principles (**DGPPs**).

Our key messages are:

Regulation must be proportionate and consistent

- A least-cost transition will be enabled by harmonising the DGPPs with the Authority's 2019 distribution pricing principles. A standalone reform of the DGPPs is not efficient or beneficial.
- Transaction and search costs are proportionately much higher for smaller customers. Heavy regulatory intervention, complex bespoke pricing, and pioneer schemes should be reserved for the largest customers to avoid unnecessary administrative burdens that ultimately come at a cost to all consumers.
- We agree with an enabling, non-prescriptive approach to capacity pricing. Prescriptive interventions may stifle innovation and limit opportunities for customer-centric improvements.

Guidance is helpful for mixed use cases

- Mixed injection & offtake connections are becoming increasingly common and were not anticipated by the current DGPPs.
 - Authority guidance and worked examples will pre-empt inconsistent pricing of mixed connections across New Zealand but need to be complemented by explicit principles.
 - Appendix A and E scenarios should also include calculating connection and ongoing lines charges for a standalone battery, used solely to arbitrage the energy market.
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**Flex tenders
complement
upfront and
ongoing charges**

- The paper highlights the need to reflect the value of injection to defer or avoid network investment, minimising charges for connection and ongoing lines charges.
- Connection and lines charges should be agnostic to the type of resource (injection or offtake) but can be complemented by additional payments or rebates for flexibility.
- Flexibility tenders provide sharper signals than lines charges and can be more targeted at deferring specific investments by requiring firm response when networks are congested.

We are committed to working with the Authority and other organisations on reforms that will ensure a timely, least-cost transition. Our responses to the Authority's specific consultation questions are tabulated below.

We are always keen to meet with the Authority to discuss and develop the ideas in our submissions. In the meantime, if you have any questions or would like to talk further on the points we have raised, please contact Emma Wilson [REDACTED]

Nāku noa, nā,
[REDACTED]

Emma Wilson
Head of Regulatory, Policy and Markets
POWERCO

Powerco response to consultation 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?	<p>Yes. The DGPPs were a political initiative from 2006 to stimulate investment in distributed generation (DG) by maximising the opportunity for DG connection. Interpretation and application may now inadvertently be creating a barrier to the least-cost transition to an expanded low-carbon electricity system. A least-cost transition will be enabled by harmonising the DGPPs with the Authority's standard distribution pricing principles.</p> <p>Our preference would be to simply repeal the DGPPs entirely and clarify how the existing 2019 distribution pricing principles apply to all connections – injection, offtake and mixed - in their absence. If the Authority is determined to preserve them, we support the proposed changes to the DGPPs to clarify how EDBs should interpret the incremental cost principle for consistent practice across New Zealand.</p> <p>We agree that the new requirement for distributors to offer a negative export tariff to small consumers is relatively untargeted and that a similar approach for large connections would be inefficient but note that targeted payments for flexibility rather than posted lines charges do allow lines companies to avoid investment. This is the basis of Powerco's current portfolio of flexibility tenders¹.</p>
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?	<p>Partially. The Authority's clarifications are helpful in the light of wide and diverse interpretation of the incremental cost rule across EDBs.</p> <p>Powerco does currently include a full allocation of incremental costs in its connection charges for injection, consistent with the revised guidance in the consultation paper. We agree with 3.2(c) that without guidance around cost-sharing for anticipatory investments, generators' decisions around investment timing will be distorted by their "position in queue".</p>
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?	<p>Partially. If EDBs interpret the incremental cost limit to exclude the long-run marginal cost of network augmentation, then access seekers will not be making efficient decisions about their demands for new export hosting capacity.</p> <p>As the Authority notes, reforming the DGPPs is an opportunity to clarify what practices are consistent with the incremental cost principle. It would be helpful to provide explicit clarification that EDBs can use commercial mechanisms to allocate capacity (for example an auction mechanism) as alternatives to legacy mechanism (such as first in first served capacity right rules) to better maximise the benefits of market-based changes.</p>

¹ <https://www.powerco.co.nz/our-partners/flex-solutions>

	<p>We note that the Authority's current work in the Network Connections Project (Stage One), refers to problems with "first-come, first-served". It may be helpful for the Authority's final decision to acknowledge this linkage and make an explicit link to capacity allocation (rather than queue management per se).</p>
<p>Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?</p>	<p>Yes, regulation in monopoly markets is necessary to protect customers. However, as we have previously suggested it would be simplest to repeal the DGPPs entirely and clarify how the existing 2019 distribution pricing principles apply to all connections – injection, offtake and mixed - in their absence.</p>
<p>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?</p>	<p>Yes. Allocating residual costs to producers would flow through to higher wholesale and retail electricity prices which offtake consumers would ultimately end up paying.</p> <p>As we discuss in our answer to question 22, updating the DGPPs provides the opportunity to clarify appropriate pricing practice for BESS units given their hybrid nature.</p> <p>The Code's definition of "Producer" reflects a single role in the energy market role – providing input services to the electricity industry. When batteries time-shift energy, they are not strictly "producing" energy and will incur charges from residual cost allocation when charging even if they aren't adding any incremental costs.</p> <p>As offtake pricing becomes more cost reflective there may be no residual cost allocation to charge batteries when networks are uncongested and energy prices are low.</p>
<p>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?</p>	<p>Yes. The key issue is that all distribution charges provide an efficient investment signal and that injection, offtake and mixed connections are treated consistently.</p>
<p>Q7. Do you consider that the proposed amendments to language and framing would support more efficient pricing? Why?</p>	<p>Yes. The changes will better enable EDBs to interpret the DGPPs consistently so nationwide investment in new generation and BESS will be more efficient.</p>
<p>Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing</p>	<p>Strongly agree. Backstop regulation shouldn't be too prescriptive because it can cause unnecessary compliance costs, duplication, and potentially limits EDBs' flexibility and ability to innovate. Focusing on outcomes instead of being</p>

<p>is appropriate at this stage? Why?</p>	<p>prescriptive of how to get there allows EDBs to develop innovative ways to provide information and services to their customers.</p> <p>It is possible that the lumpier nature of injection connection requests may mean allocating capacity costs based on estimates may not be as easy or practical as for offtake.</p>
<p>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?</p>	<p>No – administering pioneer schemes is extremely complicated and heavy administrative burden. Standardised capacity charges might be a better alternative to address position in queue issues related to upgrades.</p>
<p>Q10. Do you consider that pioneer schemes should also cover network injection capacity? Why?</p>	<p>Yes, if discretionary. The cost of administering pioneer schemes must be proportionate to the problem they are addressing. Giving EDBs discretion to decide a minimum threshold for pioneer schemes seems prudent.</p>
<p>Q11. Do you consider that the proposed non-discriminatory pricing requirements would improve confidence that investors are safeguarded from discriminatory pricing? Why?</p>	<p>No. These proposed requirements are duplicative and unnecessary. If there is evidence that EDBs are discriminating in favour of related parties, they will be in breach of section 36 of the Commerce Act. While this anti-competitive conduct would clearly be undesirable, it seems unnecessary to have additional rules to prohibit it – the Authority could bring a case to the Commerce Commission.</p>
<p>Q12. Do you agree with the proposed application provisions, in particular with regard to opting out, retrospectivity and secondary networks? Why?</p>	<p>Yes. With the caveat that harmonising contracts must be achieved through bilateral agreement and without removing any contractual rights from either party.</p>
<p>Q13. Do you agree with the proposed commencement provisions above? Why?</p>	<p>Yes, with adjustment. In December 2025, the Authority revised its definition of “small business consumer” eligible for negative charges (rebates) when supplying power to the network at peak times as a network connection size up to 45kVA and that exports up to 45kW of electricity back to the network at peak times².</p> <p>Given that the purpose of regulating different commencement timing for injection connection charges is to reflect the relative simplicity of smaller connections, it would be consistent to use the same 45kW threshold to distinguish between small and large injection connections.</p>

² <https://www.ea.govt.nz/news/press-release/clarification-on-small-business-eligibility-for-peak-export-rebates/>

Q14. Do you have any suggestions for how we can most effectively support successful implementation?	<p>As the primary intention for the changes to the DGPP is to eliminate differences in interpretation between EDBs, supplementing implementation with practical resources such as online training and Q&A sessions and rapid amendments to address material issues would be helpful to support initial and ongoing implementation of the changes.</p>
Q15. Do you have any suggestions for effective monitoring and reporting, including proposed changes to charge reconciliation requirements?	<p>The Authority's proposals for reporting and monitoring pricing methodologies are consistent with those for the reconciliations and the current secure transfer portal for these documents is a practical mechanism.</p> <p>Given the cost of reporting and monitoring, it is important that the Authority uses the data to improve outcomes for consumers.</p> <p>We note that provisions for disputes resolution mirror the those included in the recent code amendments for connection pricing effective April 2026. These recent requirements for connection pricing may be revised to address practical issues over coming months. Rather than needing to reflect the same changes in the code amendment for the DGPP changes, it would be more practical to cross reference to the other provisions rather than hard coding them so that any future changes would need to be made in multiple places.</p>
Q16. Do you agree it is appropriate to give distributors relatively wide discretion as to how they implement capacity charges for injection connections? Why?	<p>Yes – as we note in our answer to question 8 above, it is possible that the lumpier nature of injection connection requests may mean allocating capacity costs based on estimates may not be as easy or practical as for offtake.</p> <p>While MDAG's recommendation 5 for price-driven secure distribution dispatch (footnoted on page 45 of the consultation) will be the first-best long-term solution for a highly decentralised electricity system, the direct and indirect costs of such a fundamental change to the operation of distribution networks would be material.</p> <p>As we argued in our original submission on the Authority's multiple trading arrangements proposal³, the cost of requiring every distributor and every incumbent retailer to change contracts, processes and IT systems and to assign roles, responsibilities, costs, revenues and liabilities will be in the order of hundreds of millions of dollars across central market systems and all industry participants.</p> <p>MDAG's recommendation is justified by the avoided costs of network investment. These benefits must be additional to the avoided investment in distribution networks that will be achieved through low-cost initiatives such as</p>

³ <https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/submissions/2025/electricity-authority---multiple-retailing-and-switching.pdf> see cost analysis on page 11

	<p>Powerco's current flexibility tenders⁴ if price-driven secure distribution dispatch is to be in the long-term benefit of consumers.</p> <p>It's a good and important idea, but it's not a priority at the moment, so wide discretion is important.</p>
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?	<p>Yes. The lumpiness and network-location specificity of larger injection connections makes it difficult to use average costings efficiently. In our experience, it's necessary to look at all connection requests for injection larger than 300kW individually to ensure application specifics don't result in the inefficient under-recovery of costs which would burden existing offtake customers inefficiently.</p>
Q18. Is there any specific guidance that would be particularly helpful for distributors implementing capacity charges for injection?	<p>In our answer to question 2 we suggest specific guidance on the use of auction-based mechanisms or other commercial mechanisms for allocating capacity, to achieve the incremental cost principle, would be helpful in EDBs better understanding the use of novel pricing approaches.</p> <p>Similarly, it would be helpful for the Authority's DGPP reforms to clarify how, and if, export price signals should be used to provide an incentive for customers (or their agents) to self-curtail on-site generation export and increase load (including BESS charging) in export constrained locations.</p>
Q19. Do you consider that inconsistent treatment of transmission connection charges for large generation projects may distort investment? Why?	<p>Yes. Any arrangements under which injection customers can avoid transmission charges by connecting to distribution networks will distort their decision making inefficiently.</p> <p>In our experience, access seekers balance many factors when applying for connection. Costs are clearly important but the time to connect and location can influence investment decisions equally.</p>
Q20. Do you have a view on the best option to address the connection charge distortion issue? Please explain your rationale.	<p>?</p>

⁴ <https://www.powerco.co.nz/our-partners/flex-solutions>

Q21. Do you consider that the restriction on recognising transmission benefits should be reconsidered if the other proposed Code amendments are made? Why?	<p>Yes. As we note in our answer to questions 8 and 16 above, the value of injection to deferring or avoiding planned growth capex is signalled softly in connection and lines charges but can be rewarded directly with targeted payments or rebates where it responds directly to a call for flexibility services. The benefits of distribution-embedded flexibility resources can include transmission growth capex deferral. Powerco is working with Transpower in the Western Bay of Plenty to realise these coincident opportunities.⁵</p>
Q22. Are there any other matters that you consider important for us to take into account in our reform of the DGPPs?	<p>Given the rapidly changing costs and capability of injection resources, the opportunities for commercial deployment are changing all the time. The Authority's non-prescriptive, enabling approach to the DGPP reform should avoid adverse unintended consequences of prescribing how connections should be priced prematurely.</p> <p>The worked examples that the Authority provides in appendix A and E (residential rooftop solar and mid-scale on-farm solar) are helpful. It would be useful to provide a third scenario of a large distribution-connected battery that is installed solely for the purpose of energy price arbitrage but charges slowly (say a maximum of 10kVA) and discharges rapidly (say a maximum of 500kW). We have provided a suggested example in an appendix to this submission.</p> <p>Alignment with other reforms the Authority has underway, and avoiding duplication are important in the Authority considering this DGPP reform. As we note in our response to question 11, the non-discrimination provisions duplicate section 36 of the Commerce Act.</p>
Q23. Do you have any comments on the consumer impact analysis methodology or findings?	<p>As the Authority notes in A.36, it's difficult to conclude much from the average reduction in annual cost per offtake connection in table A.1 because it's small, particularly when transmission connection charges are excluded (as clarified in the 21 April 2026 amendment to the tables in appendix A. The national variation by company in table A.2 justifies a non-prescriptive, enabling approach to DGPP reform.</p>
Q24. Do you agree with the objectives of the proposed amendment? If not, why not?	<p>The primary problems the Authority has identified are inconsistent interpretation of the incremental cost rule across EDBs and the position in queue hold ups. To the extent that the amendment addresses these proportionately, they are in customers' interests.</p>
Q25. Do you agree the benefits of the proposed amendments would outweigh the costs?	<p>The information provided does not enable Powerco, or the Authority, to reach a conclusion that benefits outweigh costs. Comparing forecast EDB capex with business support costs is hardly a cost benefit analysis. It would be more rigorous to attempt to quantify the inefficiency of the current DGPPs and discount the costs of relieving them.</p>

⁵ <https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/submissions/2025/commerce-commission---transpower-western-bay-of-plenty-major-capex-project-proposal.pdf>

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.	<p>The proposed Code amendment is not Powerco's preferred option.</p> <p>In our submission on the DGPP Issues Paper⁶ we suggested that the Authority can address the issues it identifies by repealing the DGPPs and developing guidance as to how the pre-existing 2019 distribution pricing principles apply to DG connections in their absence.</p> <p>These proposed pricing principles are worded generally – so apply to both injection and offtake. It would be helpful if the Authority clarified how EDBs should apply them to DG connections of different sizes and in different circumstances (mixed/dedicated connections) but this could be done by updating the <i>Distribution Pricing: Practice Note</i> in much the same way that Appendix C of the <i>Second Edition v 2.2</i> is a practice note on Transmission charge pass-through. This would simplify the Code and improve its internal consistency while achieving the same benefits as the Authority's proposed amendment.</p>
Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	<p>Yes</p>
Q28. Do you consider that the Authority's preferred high-level settings for injection pricing are consistent with the distribution pricing principles? Why?	<p>Yes.</p>
Q29. Do you consider that consolidating distribution pricing methodology requirements into Part 6B would improve clarity and consistency? If not, why?	<p>Yes, consolidating the distribution pricing principles and DGPP together into part 6B would improve clarity and consistency.</p>
Q30. Do you have any comments on the drafting of the proposed amendment?	<p>We support the changes proposed in the ENA's legal review.</p> <p>The amendments reflect the Authority's "price as load first" position. The policy intent behind this position seems more to ensure that EDBs price mixed connections both as injection and offtake to ensure that the prices a generator or battery pay include an appropriate amount of residual cost. It is not that offtake pricing is fundamentally more important than injection pricing. Injection</p>

⁶ <https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/submissions/2025/electricity-authority---distributed-generation-pricing-principles.pdf>

	<p>and offtake capacity are not coincident - when a network is congested for offtake then any injection will relieve that congestion and vice-versa.</p> <p>Rather than the amendment as drafted</p> <p><i>"the connection enhancement cost allocation requirements and the capacity costing requirements must be applied to the <u>offtake</u> load component of the application before Part 6<u>subpart 3</u> is applied to the distributed generation <u>injection</u> component of the application ..."</i></p> <p>drafting this as</p> <p><i>"<u>both</u> the connection enhancement cost allocation requirements and the capacity costing requirements must be applied to the <u>offtake</u> load component of the application before Part 6 is applied to the distributed generation <u>and the injection</u> component of the application <u>under subpart 3</u> ..."</i></p> <p>would avoid perverse unintended outcomes</p>
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Additional worked example for appendices A and E

Standalone Battery Energy Storage System

In this case, a merchant trader is investing in a medium-scale battery, primarily for arbitraging the energy market – charging when spot electricity prices are low and discharging when they are high.

Generally the trader intends charging the battery slowly during off-peak periods and exporting rapidly during periods of scarcity.

They chose a part of the country where nodal prices are high and approach the local distributor to understand the costs of installing a battery: limiting the charging rate to 10kVA but allowing it to discharge at a maximum of rate of 500kW.

The distributor calculates connection charges driven by the maximum power capability in both directions. The offtake rate of 10kVA includes an allocation of residual costs where the injection rate of 500kW is just allocated the incremental costs attributable to hosting that capacity.

In addition to fixed charges, the distributor's variable charges reflect network congestion, for example peak solar export on some rural feeders in summer and winter evening demand peaks in urban areas and rural feeders during the milking season.

On this network, the distributor is anticipating the need to upgrade some specific feeders to accommodate demand growth and are running tenders for flexibility providers to offer local demand reduction or injection in response to a signal from their control room so that they can defer these planned upgrades for 3 years.

The trader forecasts that the local network congestion periods are similar to the spot price peak periods in which they intend to export power to arbitrage the spot market. They chose to locate the battery on one of the feeders where the distributor is running a flexibility tender. In return for an availability payment, the trader reserves some battery capacity to be able to meet calls for flexibility when the feeder is congested, and accept the spot price at that time.

Three years later, the distributor upgrades the network feeder and ends the scheme for flexibility payments. The trader looks at options to move the battery elsewhere but decides to leave it where it is and locate a newer, larger battery elsewhere on the network where the distributor is running similar flexibility tenders to defer other planned network augmentation.