19 May 2026

Electricity Authority
PO Box 10041
Wellington 6143

By email to: distribution.pricing@ea.govt.nz

Reforming Distributed Generation Pricing Submission

Executive Summary

Westpower supports the proposed Distributed Generation Pricing reforms. They provide long-overdue tools to manage growing distributed generation (**DG**) on our largely rural network, restoring control over capacity, costs, and investment timing in a way the current framework does not.

The reforms reduce hidden consumer subsidies, lower regulatory risk compared to the existing cap framework, and better support efficient DG growth on a constrained network.

Our detailed responses to each question are set out in the attached submission. We detail below some of the key parts of the reforms that Westpower supports, and those parts where we seek modifications to what has been proposed.

Reforms we Support

– Injection charges to recover DG-driven costs such as inspection, protection, voltage management and transmission impacts are currently socialised to existing consumers.

– Capacity-based tools for constrained feeders treating injection capacity as an economic resource, enabling staged upgrades, and cost-reflective signals rather than blunt export limits.

– Addressing first-mover risk, including network injection capacity costs in incremental cost calculations, with optional (not mandated) pioneer schemes.

– Fairer transmission cost allocation injection-related transmission charges attributed to DG connections, rather than consumers. This is of particular importance on the West Coast.

Proposed Modifications/Refinements

– Mandated parity between injection and offtake pricing. This would load residual costs onto generation, distort investment signals, and disproportionately disadvantage rural distribution-connected generators.

– Prescriptive injection capacity costing methodologies forcing uniform approaches. This increases complexity, reduces flexibility for local conditions, and would impose costs that outweigh benefits in small networks like ours.

– Implicit expectation of universal congestion pricing which is unnecessary across much of our network, expensive to design and explain, and potentially confusing for customers. We rely on engineering-led and capacity-based solutions.

Concerns with the Implementation Timeline

Westpower wishes to specifically highlight concerns with the implementation timeline. The proposed commencement date creates a serious practical problem for distributors, and ultimately for the consumers we serve.

Including the required 3 month notice period, DG pricing would need to be finalised by 31 October 2026. At that point, final budgets and critical datasets are simply not available. This forces use of inconsistent data across distribution and DG pricing.

To align with distribution pricing timelines, any pricing notification cannot occur before 28 February 2027, making 1 June 2027 the earliest responsible implementation date.

However, given the volume of concurrent EA requirements, and the need for adequate time to develop well-informed pricing, we recommend a commencement date of 1 June 2028. Rushing this risks poor outcomes for consumers.

Conclusion

Westpower appreciates the Authority's work on this review and the constructive engagement with stakeholders and looks forward to continuing to work with the Authority to establish regulation that supports efficient investment for the benefit of all electricity network users and contributors.

If you have any questions about this submission please contact Lisa Leyland, Regulatory and Legal Manager, Westpower

Yours sincerely

Lisa Leyland

Regulatory and Legal Manager

Westpower

Name	
Organisation	Westpower Limited

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?	Yes. Westpower agrees with the background and context set out in the consultation paper as a short-term measure, but believes long-term implications may result in unfair treatment to all connections, similar to the Low Fixed Charge regulations that proved to be inefficient in the long-term. From Westpower's perspective as a rural distributor, the current Distributed Generation Pricing Principles (**DGPPs**) no longer reflect how costs are incurred in practice. In particular, cumulative impacts of multiple injection connections, exposure to transmission-related costs, and constraints on long rural feeders are not well addressed under the existing framework.
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. Workability challenges exist where resources are allocated over several functions, making it difficult to attribute cumulative and programmatic costs to individual connections. This leads to cross-subsidies from offtake consumers. Position-in-queue could become a problem and congestion pricing is preferred.
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 framework tends to under-allocate injection-driven costs to those who create them, while not providing clear mechanisms to reward injection that genuinely benefits the wider community (such as deferring upgrades or improving resilience). This outcome is not consistent with community fairness.
Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?	Yes. Continued regulation is necessary to safeguard community interests. Westpower is a network owned on behalf of the community. Clear, regulated pricing principles give confidence that: • charges are fair and transparent, and • no group is advantaged or disadvantaged at the expense of others.
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?	Yes. Westpower agrees consumers should remain residual payers of non-incremental network costs. Allocating residual costs to producers would deter efficient generation investment and increase long-term costs to consumers.

Questions	Comments
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. Westpower supports the reframing of the incremental cost rule to a requirement that charges 'must reflect a reasonable estimate of' rather than 'must not exceed' incremental costs.
Q7. Do you consider that the proposed amendments to language and framing would support more efficient pricing? Why?	Yes. Westpower considers the proposed changes to language and framing would support more efficient pricing outcomes, particularly by clarifying the treatment of cumulative, programmatic, and capacity-related costs and benefits.
Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing is appropriate at this stage? Why?	Yes, in principle. Westpower supports an enabling approach that allows distributors to select tools appropriate to local conditions. It is important that capacity pricing is not implicitly mandated, particularly for rural networks.
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?	Westpower supports the ability for EDBs to use pioneer schemes where there is a clear benefit, but does not support mandated pioneer schemes. There are limited circumstances in which pioneer schemes are likely to benefit first-mover injection issues, and therefore mandating pioneer schemes would add process and compliance costs, without materially altering investment decisions or pricing.
Q10. Do you consider that pioneer schemes should also cover network injection capacity? Why?	Yes. Westpower agrees pioneer schemes should cover network injection capacity where last-straw pricing remains in use, noting this is particularly important for rural feeders and substations with limited headroom.
Q11. Do you consider that the proposed non-discriminatory pricing requirements would improve confidence that investors are safeguarded from discriminatory pricing? Why?	Yes. Westpower supports introducing a non-discriminatory pricing requirement to enhance investor confidence and provide clear regulatory guardrails, particularly where distributor ownership structures are evolving.
Q12. Do you agree with the proposed application provisions, in particular with regard to opting out, retrospectivity and secondary networks? Why?	Westpower generally agrees. In particular: • Applying updated principles to existing connections for lines charges for non-specific contracted consumers is appropriate; • Transition arrangements should recognise the inability to modify existing contractual and investment commitments; • Retaining current treatment of secondary networks is appropriate at this stage.

Questions	Comments
Q13. Do you agree with the proposed commencement provisions above? Why?	No. The timeline is out of phase with the publication of distribution pricing. Including the 3 month notice period, pricing for DG would need to be finalized by 31 October 2026. At this point, final budgets and other datasets are unavailable, leading to inconsistent data usage in distribution and DG pricing. For continuity, pricing publication needs to coincide with distribution pricing notification which would be no earlier than 28 February 2027. This would mean implementation of DG pricing should not commence until 1 June 2027. Westpower also believes the proposed timing is too short to allow fully informed development of DG pricing and therefore recommends a commencement date of 1 June 2028. The Authority also needs to consider the workload of all other EA requirements and regulations at this point in time, so as not to overburden distributors.
Q14. Do you have any suggestions for how we can most effectively support successful implementation?	Westpower recommends: • Practical guidance and worked examples tailored to rural distributors; • Clear expectations around proportionality; and • Ongoing engagement during early implementation to resolve minor issues quickly. Westpower notes that there is insufficient time allowed for these actions to occur in a timely manner.
Q15. Do you have any suggestions for effective monitoring and reporting, including proposed changes to charge reconciliation requirements?	Monitoring should focus on outcomes that matter to communities: • whether costs are fairly allocated, and • whether pricing decisions help avoid unnecessary network investment. Reporting requirements should remain proportionate to the scale of the network.
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. Westpower agrees distributors should retain wide discretion in implementing capacity charges for injection, given the highly localised nature of distribution network constraints.

Questions	Comments
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. Larger injection connections should be priced based on their specific impacts and benefits. This would ensure community costs are protected while still enabling efficient investment.
Q18. Is there any specific guidance that would be particularly helpful for distributors implementing capacity charges for injection?	Guidance would be helpful on: • Simple capacity-based approaches suitable for rural networks; • When congestion pricing is likely to be efficient versus alternative tools; • How to phase approaches as network conditions evolve.
Q19. Do you consider that inconsistent treatment of transmission connection charges for large generation projects may distort investment? Why?	Yes. Different treatment of transmission and distribution connections can distort investment choices and increase overall costs borne by regional communities like the West Coast.
Q20. Do you have a view on the best option to address the connection charge distortion issue? Please explain your rationale.	Any solution should consider the limited transmission alternatives available to small, remote communities and should not penalise distribution-connected generation simply due to geography.
Q21. Do you consider that the restriction on recognising transmission benefits should be reconsidered if the other proposed Code amendments are made? Why?	Potentially yes, if safeguards are strong. In some cases, local injection may reduce upstream transmission costs or improve resilience. Any recognition should be carefully designed to avoid double-counting and protect consumers.
Q22. Are there any other matters that you consider important for us to take into account in our reform of the DGPPs?	The Authority should continue to consider how: • resilience, • outage mitigation, and • local flexibility services are valued within pricing frameworks, particularly for isolated or high-risk regions.

Questions	Comments
Q23. Do you have any comments on the consumer impact analysis methodology or findings?	Westpower considers the consumer impact assessment reasonable and notes that while national averages appear modest, impacts may be more significant in smaller networks, reinforcing the importance of removing embedded subsidies early.
Q24. Do you agree with the objectives of the proposed amendment? If not, why not?	Yes. The objectives align with community ownership principles of fairness, efficiency, and long-term benefit to consumers.
Q25. Do you agree the benefits of the proposed amendments would outweigh the costs?	Yes. From a community perspective, the benefits of fairer cost allocation and better investment signals are likely to outweigh implementation costs.
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.	Yes. The proposed amendments are preferable to maintaining the status quo or removing regulation altogether, both of which risk disadvantaging consumers.
Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	Yes. The amendments promote efficient operation and long-term consumer benefit consistent with the Electricity Industry Act.
Q28. Do you consider that the Authority's preferred high-level settings for injection pricing are consistent with the distribution pricing principles? Why?	Yes. The proposed framework aligns with established principles while allowing appropriate flexibility for community-owned networks.
Q29. Do you consider that consolidating distribution pricing methodology requirements into Part 6B would improve clarity and consistency? If not, why?	Yes. Consolidation improves transparency and accessibility, which supports meaningful engagement by ownership trusts and communities.
Q30. Do you have any comments on the drafting of the proposed amendment?	The drafting is generally sound. Westpower encourage: • clear guidance for community-owned and rural distributors, and • consistent use of injection/offtake terminology throughout the Code.