Appendix A: Submission form

Transmission Pricing Methodology amendments 2026

Please email your submission to networkpricing@ea.govt.nz by 5pm, 24 July 2026.

Lodestone Energy is an independent generator-retailer operating five utility-scale solar farms, with further sites under construction and a consented pipeline increasingly paired with battery energy storage. We connect to both distribution networks and to the national grid and fund the full incremental cost of every connection we make.

We have submitted separately on Chapter 5 using the Appendix B form. No part of this submission is confidential.

Submitter	**Lodestone Energy Limited** **Contact: Peter Apperley, GM Engineering & Technology**

#	Question	Response
Chapter 3: Context and approach		
1	Do you agree with the assessment approach and criteria set out in this chapter? Please explain your reasons.	**Broadly yes, but with three additions.** Predictability for parties making irreversible investment decisions should be an explicitly stated criterion. "Practical considerations" tends to be read as administrative cost to Transpower and compliance cost to customers. For a developer the decisive question is whether transmission exposure is knowable and forecastable at a project's financial close. Cost that is unpredictable, unmanageable and uncontractable is priced by lenders through higher debt service or reduced leverage, and raises the cost of delivered energy. It also runs the very real risk of compromising project economics and, ultimately, viability. It is no basis upon which to try to invest in long-term infrastructure. Distributional effects that fall repeatedly on one class are efficiency effects. We accept paragraphs 3.10 and 6.32 where effects are broadly random. Where they fall consistently on independent generators connecting in remote regions, they alter entry decisions and have ceased to be merely distributional. Each proposal should be tested for consistency with the parallel workstreams, including distributed generation pricing principles reform, distribution connection pricing, BESS wholesale arrangements and the decision paper should clearly state how.
2	Do you consider an alternative approach or assessment criteria	**Not a different framework, but three criteria we would add.**

	should be used? If so, please describe these and explain why these would be better.	**A financeability test**: can a party accurately estimate its exposure over the investment horizon, within a reasonable band, before committing capital? **A proportionality test**: is the burden proportionate to the size of the participant? Exposures calibrated to large vertically integrated participants can be materially disproportionate for a small independent generator, with significant consequences for investment. **A standing technology and fuel neutrality test**. The Chapter 4 problem arose because the simple method assumes a binary load-or-generation model. The same will recur for hybrid configurations, and a standing test would surface it at design stage rather than by later correction. On quantification, the reasoning at paragraph 3.26 does not hold uniformly: Figure 2, Figure 6 and Table 4 show quantification is possible where the Authority has the data. Where the effect on a representative independent generator or BESS can be quantified, it should be, because aggregate figures conceal effects that are material at project level.
Chapter 4: BBC simple method treatment of battery storage		
3	Do you agree that offtake by battery storage should be exempt from the Demand Factor? Please explain your reasons.	**Yes, strongly.** The demand factor reflects the relationship between the value of lost load and wholesale prices. A battery's loss from an outage is foregone margin, not lost load. Scaling its offtake by 1.67 treats stored energy as consumed, when the end-user who ultimately consumes it is separately charged. The simple method is now the only outlier. Connection charges were corrected in 2024 to a greater-of basis and residual charges already treat a battery as load only to the extent of its losses. The magnitude is material. On Figure 2, the status quo gives battery offtake a final allocator of 0.171 against 0.102 for the same quantity of injection, a premium of roughly two thirds on identical use of the same assets, sitting on top of already concentrated allocators in the regions shown in Figure 3. Embedded storage must be resolved. Footnote 24 suggests a host customer "can ensure" pass-through charges exclude the demand factor. That is an expectation, not a mechanism. Most storage we expect to build will sit behind a distribution

		connection, and if the correction reaches only grid-connected batteries, the defect migrates to embedded storage and is absorbed in a pass-through the embedded party cannot see or contest. The Authority must state where this will be resolved rather than leaving it between workstreams.
4	Do you prefer any of the alternative options discussed for the treatment of battery storage under the simple method? Please explain your reasons.	The proposal is the right immediate step. Our preferred enduring outcome is the greater-of approach combined with removal of the demand factor. We support exempting battery storage from simple method benefit-based charges provided the same exemption was given to distributed generation. Removing simple method investments from benefit-based charges and recovering them through the residual charge should be within scope for Workstream 2.
5	Do you agree that the proposed amendment for battery storage offtake should be made ahead of Transpower's next phase of its operational review, when it will review the simple method? Please explain your reasons.	**Yes, and the Chapter 9 proposal strengthens rather than weakens the case.** The Authority's pipeline figures show 100MW committed for later in 2026, 277MW actively pursued for 2027 and 2028, and around 6,500MW in development. Allocations apply for the life of investments made in the period, so every battery commissioned before Workstream 2 concludes carries the overcharge permanently. The Authority cannot consistently defer this fix on the basis that Workstream 2 will address it while extending the period over which the unfixed method operates. Transpower's implementation questions go to how a correct principle is applied, not to whether it is correct.
6	Do you have any comment on the drafting of the amendment to the treatment of battery storage in Appendix C?	**Yes, we make the following five points:** (a) The definition of F reads "where that a customer is a member of a regional demand group". This appears to be a drafting error – should this be "where that customer is …". (b) F appears to operate as a binary at customer level. A customer may be in a regional demand group partly through battery offtake and partly through genuine end-use load at the same connection. Confirm the drafting apportions rather than switches, and amend it if it does not. (c) Hybrid solar-plus-BESS behind a single connection point is not addressed. Where

		metering does not separately identify battery offtake from station load or generation, the drafting gives no guidance. This should be resolved here rather than in the hybrid consultation, which comes later and would leave the ambiguity live through 2027/28 and 2028/29. (d) Embedded battery storage is not addressed. See Q3. (e) Schedule 12.4 defines battery storage broadly, including hydrogen and pumped hydro. The 19 May 2026 consultation proposes a narrow electro-chemical definition of BESS. Confirm which governs for clause 61 and whether the divergence is deliberate.
Chapter 6: Applying updated WACC without a lag		
13	Do you agree with the Authority's assessment of the consequences of the WACC lag? Please provide your reasons.	**Yes.** It is a timing misalignment with no material administrative benefit, and the audited-actuals rationale is preserved for asset values and depreciation. The complexity limb matters most to us. Two WACCs applying for two of every five years makes charge forecasting materially harder for a developer and its lenders. At our Kaitaia solar farm, consecutive annual increases in BBCs of approximately 37% and then 20% combined a WACC step with movements in sub-$30m simple method investments. Disentangling which portion is attributable to what, and when the remainder arrives, is not a task a small participant – or indeed any participant - should have to undertake to understand a regulated charge. This is unnecessary ambiguity. On distributional impacts we agree with paragraphs 6.31 to 6.33. Retaining a known distortion in the hope that a future WACC movement reverses its effect is not a principled basis for a Code provision. We ask the Authority to publish an indicative transition impact by customer class alongside its decision.
14	Do you agree that, because the efficiency impacts will likely grow over time, the Authority should address this WACC lag issue now? Please explain your reasons.	**Yes.** The distortion scales with the benefit-based share of revenue, which is growing. The Authority's own illustration is around $61m per annum for two years had the RCP3 to RCP4 change applied without a lag, against benefit-based charges of $302m in 2025/26.

		The implementation case is unusually clean: the change takes effect at an RCP boundary on 1 April 2030, with no mid-period adjustment, no wash-up and nearly four years' notice. Deferring means RCP6 or later, against a materially larger benefit-based asset base.
15	Do you have any comment on the drafting of the amendment to address the WACC lag in Appendix C?	**No.**
Chapter 7: Batching BBC adjustment events		
16	Do you agree with the proposal to allow Transpower to batch and process BBC adjustment events at a single annual date? Please provide your reasons.	**Yes.** Complexity, volatility and uncertainty in benefit-based charges is our principal, practical concern with the TPM. Fewer unpredictable within-year movements matters to a party operating under project finance covenants, where an unbudgeted increase in a fixed operating cost has significant consequences beyond the amount itself. At a high level, the New Zealand electricity system cannot afford to send such confused investment signals. Investor confidence in the sector is vital and that goes to predictability. Footnote 46 is the strongest point in the chapter: charges currently depend on the order in which adjustment events happen to be processed. That is an arbitrary determinant of a regulated charge with no economic content, which a customer cannot anticipate, model or verify. Batching removes it and this needs to happen quickly.
17	Do you agree that the causing customer should be charged from the batching date, with any adjustments for other customers to be applied in the subsequent pricing year? Please state your reasons.	**We prefer Transpower's original proposal.** The alternative gives up most of the benefit for a modest timing adjustment. Transpower's option removes backdating and wash-ups entirely and is assessed at $5.6m net present value. The alternative retains wash-ups and, as the Authority acknowledges in paragraphs 7.25 and 7.33, delivers less, in exchange for accelerating charges the Authority estimates at around 3% of benefit-based charges, and falling. The competitive neutrality comparison is also asymmetric. Independent generators connecting today compete against incumbent generation carrying a permanent structural advantage in connection and interconnection cost. A one-off timing difference of a few hundred thousand dollars at commissioning is not the material threat to competitive neutrality in this market. We offer that as a reason to weigh the point in proportion, not to disregard it. If the Authority adopts its alternative, we do not oppose it, but ask that the back-charging mechanics at footnote 51 be addressed. See Q19.

18	Do you consider it more efficient if, instead of the proposal mentioned in Q17, adjusted charges for both the causing customers and other customers should apply from the following pricing year? Please provide your reasons.	**Yes.** It is simpler, removes wash-ups entirely rather than partially, delivers the larger saving, and gives every customer a single annual date on which benefit-based charges change. It is also symmetrical: under the alternative, causing and other customers move on different dates and the relationship between them must be reconciled. Whichever option is adopted, a causing customer should receive its indicative allocation before commissioning. For a new entrant, knowing exposure at the point of investment decision is critical – this matters more than the timing question this chapter addresses.
19	Do you have any comment on the drafting of the amendment to enable batching of BBC adjustment events in Appendix D?	**No.**
Chapter 8: Removing SSI adjustment event		
20	Do you agree with the proposal to remove the SSI adjustment event? Please provide your reasons.	**Yes, with one observation.** The event has never been applied, the data is not reliably available for large embedded plant, and the five-year persistence judgement is speculative at individual customer level. Retaining it imposes compliance cost for no allocative benefit. The observation is cumulative effect. This was the only mechanism able to adjust allocations between five-yearly resets. Removing it while extending the first simple method period makes allocations more static for longer than either proposal contemplates alone. We prefer stability to precision and do not oppose removal, but the Authority should recognise the combined effect, which bears directly on Q22 to Q24.
21	Do you have any comments on the drafting of the amendment to remove the SSI adjustment event in Appendix D?	**No.**
Chapter 9: Simple method period 1 extension		
22	Do you agree with the proposal to extend the first simple method for up to two years (to end 31 March 2029 or 31 March 2030 if needed), so that Transpower can complete its operational review of its methods for benefit-based charging in a more timely manner? Please provide your reasons.	**We do not oppose extension to 31 March 2029. We do not support extension to 31 March 2030. Even the first year should be conditional on Transpower publishing the flow analysis the Authority has sought.** We support Transpower prioritising Workstream 2 and accept that specialist resource cannot easily be duplicated. Our difficulty is evidential. Period 1 allocators derive from flows measured September 2016 to August 2021, a window that closes before most of New Zealand's recent solar and wind connected.

		Extending to March 2030 would mean 2029/30 investments are allocated for their full asset life on flows measured up to nine years earlier, in a period preceding the current generation build. The Authority is not satisfied on this point either. Paragraph 9.18 records that Transpower's analysis is not sufficiently conclusive, and footnote 57 records that Transpower compared 2016-2021 data against 2018-2023 data, so much of the comparison is of overlapping observations. That cannot show that flows have been enduring across the window that matters - 2021 to 2026. We ask the Authority to require Transpower to publish a 2021 to 2026 flow analysis at simple method region level before deciding; decisions must be made on current data given the pace of industry change. If flows have been materially stable, our concern falls away, but this must be based on fact and data rather than assumption. The volume at stake is not marginal: simple method charges are estimated at $140m in 2027/28, rising around 25% and then a further 22%. Investments made in those years carry their allocations for life.
23	Has the Authority correctly identified the risk that a delay may involve efficiency costs as historical allocators risk being less than a reasonable proxy for net private benefits? Please provide your reasons.	**Yes, though understated in one respect.** We agree with paragraphs 9.15 to 9.17 and with the point in 9.30 that misallocations are baked in for the remaining life of the investments made. The error will not be randomly distributed. Flows have changed most where new generation has connected, which is disproportionately the low-voltage regions in Figure 3 where allocators are already concentrated on very few customers. Stale allocators therefore produce the largest errors precisely where each error falls on the fewest parties, and systematically against the regions where new renewable generation is being built.
24	Do you agree that, if Transpower cannot convince the Authority that the review can be completed within a timeframe that would allow simple method allocators to be updated for the 2030/31 pricing year at the latest, then Transpower should first update the simple method allocators as currently required? Please provide your reasons.	**Yes.** The five-yearly update is a codified obligation and should be the default. A method review is valuable but should not displace operation of the existing method for an open-ended period. If Transpower cannot demonstrate a credible path to updated allocators for 2030/31, the allocators should be updated and the review sequenced after that. We support the end-September 2026 assurance gate, and ask the Authority to publish

		Transpower's assurance material and its own assessment of it. Participants are being asked to accept an efficiency cost now in exchange for a delivery commitment; the commitment should be clear and visible.
25	Do you have any comments on the drafting of the amendment to extend the first simple method period in Appendix D?	**Three points, of which the third would largely address our concerns at Q22.** (a) The second year should turn on a substantive test, such as the Authority being satisfied under the paragraph 9.4 assurance process, rather than on three months' notification. Notification is procedural, not a test of whether extension is justified. (b) Include a backstop: the second simple method period commences no later than 1 April 2030 in any event. (c) Consider providing that benefit-based investments commissioned after 31 March 2028 are allocated using second period allocators once determined, rather than extended period 1 allocators. This confines the extension to a timing difference in when charges are calculated rather than a permanent misallocation. It would require a wash-up or deferred first billing and would need testing against Chapter 7, but it would give Transpower the resourcing relief it seeks without accepting a life-of-asset efficiency cost as the price.
Chapter 10: Drafting refinements		
26	The Authority is not consulting on technical and non-controversial drafting tidy-ups of the TPM, however, do you have any feedback on any potential re-drafting errors or additional suggestions?	No specific errors identified, and no objection to proceeding under section 39(3).
Chapter 11: Fixing shared connection asset allocators		
27	Has the Authority correctly identified a potential issue with the current approach to determining customers' shares of cost at shared connection assets?	**Yes.** The reasoning in paragraphs 11.17 to 11.19 is correct. Once built, a connection asset's capacity is fixed and its marginal cost is negligible, so annual reallocation on measured peaks applies a peak-based allocation to what is an economically fixed cost. The counterfactual test is decisive. No party would contract for its share of a fixed cost to vary year to year dependent upon the operating behaviour of a counterparty it neither controls nor can observe in advance.
28	Do you agree with the Authority's assessment that, while the immediate benefit of the proposal is likely	**Partially, yes.** There would need to be the ability to change the allocations if another customer (load or generation) connected.

	marginal, it is nonetheless useful to address this issue to remove volatility in shares (and thus charges) and to protect against issues becoming bigger in future?	Notwithstanding the above, we refer to our prior submission on the DGPPs regarding concerns with the distortion created by Connection Charges where a generator connects to a pre-existing GXP instead of embedding. Under the current methodology, not only does the new entrant generator get assigned the incremental costs of connection (e.g. under a TWA and connection charges for these assets) but is also then assigned a proportion of connection charges for historical sunk assets based on its AMI in proportion to the EDB AMD. Given that the EA proposal recognises that the aggregate connection charges at a node are relatively fixed, and connection charges are not sending time of use signals, we suggest consideration of an alternative cost allocation approach for connection charges. We suggest an approach based on mean annual generation vs mean annual load as the means of apportioning benefit. This is particularly relevant to solar as its relatively low capacity factor means that the existing connection charging regimes create a competitive disadvantage against other generation technologies with higher capacity factors.
29	Do you have any initial feedback on the Authority's current thinking to inform a possible amendment to the TPM (to be developed and consulted on in future) to: A: Fix cost shares at shared connection assets at those that applied in the 2026 pricing year? B: Fix the shares for a new customer at a shared connection asset based on Transpower's estimate given the capacity and type of the customer's plant, or some other approach? C: Not make any provision for those fixed shares to adjust even when there is a material and enduring change in the AMDIC of one of the customers sharing the connection asset? D: Add a clause to clarify that shares will be recalculated when a change in AMDIC by one or more customers at the shared connection asset necessitates an upgrade?	**See answer to 28 above.**

Chapter 12: Emerging connection charge and FMD issues		
30	The Authority is not consulting on proposals to address these emerging issues, but do you have any feedback or further information on these emerging issues and how these are being progressed?	**We do not agree with the provisional conclusion on either issue.** **Disconnection from shared connection location**. Reallocating a departing customer's share to the remaining customer(s) is not cost-reflective. The asset was sized for a set of customers including the one that has left; the remaining customer receives no additional capability and a larger bill, for reasons outside its control. That is neither fair, transparent or in any way good business practice. This approach conflates recovering Transpower's costs with reflecting the cost of the service the remaining customer receives. The prudent discount policy is not an adequate remedy. It places the evidential and advisory burden on the affected party to construct a credible stand-alone alternative, which is a high bar for a small participant and converts a methodology defect into a case-by-case application process. We prefer an optimised deprival valuation approach: revalue the connection asset by reference to the requirements of remaining customers, with the difference recovered through the residual charge or borne as a reduction in asset value, subject to a reasonable period for repurposing. The issue should stay open rather than be closed on a single assessment of one customer's circumstances. This also interacts with Chapter 11. Fixing shares delivers predictability against the smaller risk while leaving the larger one untouched. **First mover disadvantage type 1 issues**. We do not agree with paragraph 12.8. As a party which has been adversely impacted by over-sizing of a new connection by Transpower based on another prospective generator signing a TWA and not following through to construction, we feel very strongly about this point. Again it is neither fair, transparent or encouraging investment the electricity sector needs. The reasoning given by EA is that the size of the connection asset is a choice for the first mover. In practice, the sizing follows from Transpower's planning and the capability of the connection point, and a developer that declines the larger asset may find it cannot connect at all.

		Nor is there a counterparty with whom to manage the risk commercially: the subsequent project may not exist when the first mover commits. A risk cannot be allocated commercially to a party that is not yet at the table. Where a party defaults on obligations under a Transpower Works Agreement that Transpower entered into in good faith, the risk should sit with Transpower and be recovered through general revenue mechanisms rather than falling on the non-defaulting first mover or other customers at the location. Separately, a 10-year reimbursement profile is not financeable and requires reform regardless of where the risk sits.