20 March 2026

Transpower Limited

By e-mail: tpmreview@transpower.co.nz

Dear TPM Working Group,

Transmission Pricing Methodology (TPM) – Operational Review (workstream 1)

Lodestone Energy (Lodestone) welcomes the opportunity to provide feedback on Workstream 1 of the TPM Operational Review. This letter forms the entirety of our submission and includes some brief background on Lodestone.

Overriding Views

Lodestone Energy has accumulated some meaningful experience building 5 solar farms to date that are connected to distribution networks and to Transpower. We also have a keen sense of the capital and operating costs of projects, and how sensitive the economics are to connection, interconnection and distribution costs. To connect a distributed generation or energy storage plant (collectively referred to as DG in this submission), we are required to cover all incremental capital and ongoing connection fees associated with that connection and compete with generators who have a legacy interconnection cost advantage. With this background, we can confidently say that the combination of capital and operating costs of interconnection over and above these connection costs can singularly make a DG project unviable.

To that end, our submission is guided by the desire to make sure that any part of a TPM-based allocation of costs that jeopardises the economic viability of DG should be seriously reconsidered. In the end, allocating costs that lessen distributed generation and energy storage viability is imprudent and a detriment to consumers.

We believe that prices for our virtual rooftop contracts will be higher if TPM allocations continue to be opaque, volatile and go beyond capital recovery and maintenance of interconnection assets that directly benefit DG. This will dilute the competitive force these alternatives represent to the market.

We also hold the view that TPM does not adequately ascribe the true benefit to consumers that accrues from DG; and, on this basis, an allocation process that ignores beneficial attributes is fundamentally unfair and should be amended.

Finally, the TPM allocation process is not locked in, is subject to third party actions beyond a generator's control, and as a result generators cannot adequately plan for TPM costs. Interconnection costs are already a heavy economic burden, and undefinable future costs resulting from these actions are an impediment unto themselves. The fragile nature of project finance can be aggravated by unforeseeable cost allocations without discernible boundaries. This alone can derail a DG project given the potential magnitude of allocations.

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In summary:

- We believe solar and battery DG are a critical part of the future of generation growth to meet NZ's electrification and renewable energy goals and the TPM should be amended to narrow allocated costs to incremental capital and specific maintenance of the connection assets required to connect DG;
- The full benefit of DG would almost always outweigh the cost, and the TPM should be amended to incorporate full consideration of these; and
- The Electricity Authority should be encouraging as much distributed renewable generation and energy storage as possible and the TPM should be consistent with this.

Specific Submission to address the questions:

Notwithstanding the overriding view, we have responded to the Workstream 1 questions below, which include some key recommendations where the TPM could be immediately improved:

- Removal of the Simple BBIs completely from the benefits based charges and reallocation of these to residual charges.
- Increasing the threshold for "large plant" to between 25MW and 40MW

Question	Lodestone Response
Question 1 Do you have any comments on the process, timing and/or prioritisation of each of the Operational Review workstreams?	Lodestone has several pending projects in the detailed development phase and would appreciate expedient amendments to TPM. Lodestone welcomes any measures that will reduce the impact and complexity, and improve transparency and predictability and reduce complexity, volatility of benefits-based charges (BBCs). We doubt that the areas of focus will result in meaningful improvements for the industry recipients of BBC charges. Our experience has been that there can be large volatility in BBCs for distributed generators in remote networks from annual changes in <$30m Simple BBIs. On one of our sites we have had subsequent annual BBC cost increases of 37% and 20% due to movements in these BBIs, which have far less regulatory scrutiny than the major Transpower investments. This level of cost increase is unsustainable for small embedded generators and creates the risk of reducing confidence and deterring investment in new renewable generation by independent power producers.

Question	Lodestone Response
Question 2 Are there any other matters that we should consider as part of the Operational Review?	We think the fundamental TPM policy should be within scope of this review. In addition to the overriding view stated above, we think that there are specific examples that need to be reviewed. As an example, the fact that a deeply embedded generator adjacent to load can incur BBCs calls into question the modelling assumptions that go into the "black box". In particular, that an embedded generator in the Far North can be attributed 5% of its BBCs based on the HVDC BBI adds to the perception that the methodologies for BBI allocation are not robust or credible. **At the very least, we believe that removing Simple BBIs completely from the BBC calculation** and reallocating these to the residual charge as a common good would go a long way towards removing price volatility and complexity for many industry participants.
Question 3 Are there any matters we should specifically exclude from the Operational Review?	No.
Question 4 Do you agree with the proposed amendment - batching of adjustments with a deemed 30 June event date?	Yes – we agree with the premise that this will reduce the administrative burden on Transpower. It is not clear how it will reduce amplitude and volatility of costs for distributed generation and customers.
Question 5 Are there any other options to simplify adjustment events timing that we should consider?	No comment.
Question 6 Do you support (i) increasing the "large" plant threshold, or (ii) annual IRA updates? Which option, if either, do you prefer and why?	We agree with the principle that the adjustment should be based on the size of the plant rather than whether the plant is embedded or grid connected to avoid unnecessary incentives to embed. We would support increasing the large plant threshold based on the principle that any generation closer to the load helps to reduce the need for large transmission upgrades compared to large scale generation remote from the load. There is insufficient information for us to form a view on whether annual IRA updates would be an improvement compared to changing the "large" threshold.

Question	Lodestone Response
Question 7 If Transpower proposed raising the threshold for "large plant", what threshold(s) do you consider would be appropriate?	Between 25 to 40 MW_{AC} would be appropriate. This would go a long way to encouraging more distributed generation and energy storage.
Question 8 Are there any other options to address trigger/threshold sensitivity we should consider?	No.
Question 9 Do you agree with our initial view that the TPM should be amended to: • remove the SSI adjustment events; • clarify how Transpower should treat staged projects by adding time and certainty constraints; • remove all embedded adjustment events and SSI; and/or • switch to annual review of IRAs and remove most of the adjustment events?	Yes
Question 10 Are there any other options that we should consider to improve adjustment event workability?	No comment
Question 11 While we invite all feedback more generally on the CBA for adjustment event proposals (Appendix B) we are particularly interested in views on the following questions: a) What is your view on our approach to the CBA, including its inputs and underlying assumptions. Specifically: I. do you agree that $5k roughly captures the engagement cost with Transpower leading up to and following an adjustment event? II. when planning to connect to a distribution network, what are your costs to interact with your EDB to provide the information Transpower requires and to obtain/update price estimates for benefit-based investments? b) Does the effect adjustment events have on businesses: I. alter or delay investment commitment for embedded	a) (i) No comment (ii) EDBs have standard $5k charges for processing initial grid connection applications and then subsequent charges to support the ongoing connection application through to a connection and works agreement. If there is a cost to them engaging with Transpower to provide BBI estimates, it is implicit in the rest of the charges and not typically itemised out. More often than not, we would engage a specialist consultant to provide an estimate of BBI charges for our projects. b) (i) where BBC charges are understood in advance and factored into the business case then they don't necessarily alter or delay investment commitment. It is adverse adjustment events and unexpected changes in Simple BBIs that occur after an investment is made that reduce investor confidence and potentially deter future investment. (ii) BBCs can make some embedded generation projects economic if a particular EDB / region has larger allocations of BBCs than others. We had one potential deeply embedded <25MW project that initially had estimated BBCs that

Question	Lodestone Response
generation or offtake plant and, if so, how? II. affect plant design and location decisions for embedded generation or offtake plant and, if so, how? c) How does the current threshold of 10MW affect plant design and location decisions and how would this change if the threshold were raised to, say, 25MW?	were 3 times larger than BBCs for other sites in our portfolio. This was one key factor for ongoing delays in this otherwise shovel ready renewable project.
Question 12 Do you agree with the proposal to extend the first simple method period to the end of PY2029 or to the end of PY2030 if required?	We have no issue with this.
Question 13 Are there any other options we should consider for the second simple method period work?	As noted above, more fundamentally we have observed that these Simple Method BBIs have a much larger adverse impact on small embedded generation (and the local EDBs) than the Standard Method and Appendix A BBIs. There is limited visibility on the annual expenditure that goes into these regional buckets. While the expenditure may be small relative to the larger pool of transmission investments, these Simple BBCs are allocated to a much smaller group of network ICPs and generators, so the impact of any Simple BBI costs will fall disproportionately on customers (and generators) in remote rural networks compared to those in large urban networks. This exacerbates the rural / urban energy affordability divide. We advocate the complete removal of Simple Method BBIs from the BBC calculation and have these costs recovered through the residual charge as a common good benefit to all consumers.
Question 14 Do you agree with the proposal to clean up the TPM legal text?	Yes.
Question 15 Are there any other opportunities to clean up the TPM legal text we have not identified?	We recommend that a fundamental amendment to include our overriding view (outlined on page 1) should be included in a 'clean up' of the legal text. Lodestone would be happy to participate in the writing of any such amendments.

Question	Lodestone Response
Question 16 Do you agree that disconnection from a shared connection location creates a problem for remaining customers at that location? Do you think this is or could become a material problem?	Yes, it may be material which is the main concern. We believe it to be an unfair practice to reallocate direct costs to connected customers of a shared asset in the event of a disconnection of a customer. Revenue lost in this scenario should be recovered through general revenue recovery mechanisms and subject to a reduced valuation if the asset is not repurposed in a reasonable time period.
Question 17 What other options do you think should be considered? Are these options consistent with the intent of the TPM Guidelines?	An Optimised Deprival Valuation (ODV) style approach could be undertaken to revalue the Connection asset based on the remaining connected parties loads / generation capacity. The difference in value should be either allocated to residual charges across the general revenue recovery mechanism or be a loss in asset value to the Shareholder. The Prudent Discount Policy is less suitable, as it puts the onus and cost on the affected party to apply and provide the evidence of a credible alternative / optimised connection.
Question 18 Do you think that this is a matter that could/should be addressed through the Operational Review?	Yes.
Question 19 Do you agree that anticipatory investment in interconnection assets can create first mover disadvantage problems? Do you think this is or could become a material problem?	Yes. This is already a material issue as evidenced by historical proposed large interconnection projects to connect multiple generation projects (such as the Northland renewable energy zone and the Wairarapa wind interconnection) that have never proceeded due to FMD.
Question 20 What options do you think should be considered? Are these options consistent with the intent of the TPM Guidelines?	Funding these investments under the residual charge initially. As generators connect then charges should be shifted to BBCs in proportion to their capacity relative to the capacity of the investment.
Question 21 Do you agree that this is a matter that could/should be addressed through the Operational Review?	Yes.
Question 22 Under the FMD Type 1 mechanism, which Transpower customer(s) should bear the financial risk of second mover(s) not connecting or delaying their connection?	The possibility of default for non-completion of a TWA obligation by a party that is part of a shared asset, is a risk; and non-defaulting parties (particularly first movers) should be insulated from the risk. In the event of a party defaulting under a TWA Transpower entered into in good faith, the risk should lie with Transpower (and by default, its customers). Transpower is large enough to

Question	Lodestone Response
	create business rules to ensure reasonable protection from defaulting party risk. This is an acceptable risk to carry for Transpower as it will ensure that prudence and discipline will be used when entering into TWA agreements. Transpower should be prepared to demonstrate that proper due diligence was conducted on the defaulting party. Furthermore, other connected parties at a GXP should not incur additional annual Connection Charge costs associated with assets installed for the defaulting party under a TWA. These should be recovered from the defaulting party under some form of security mechanism by Transpower or reallocated to residual charges.
Question 23 Do you agree that the FMD Type 1 mechanism is not functioning the way it should for connection assets that benefit embedded large plants? Do you think this is or could become a material problem?	Not necessarily. In the Cyclone vs Hurricane wind farm example, if the embedded Cyclone wind farm was installed first it should not have to contribute to a TOPS scheme required to facilitate the larger Hurricane project to connect to the grid. The Hurricane project could have downsized its capacity to fit within the capacity of the transformers but chose not to. If the Cyclone WF came second, then yes, it would be fair for it to contribute to the TOPS cost.
Question 24 What options do you think should be considered? Are these options consistent with the intent of the TPM Guidelines?	No comment.
Question 25 Do you think these are matters that could/should be addressed through the Operational Review?	Yes
Question 26 Do you agree with the overall objectives of the proposed TPM Operational Review?	Yes. As noted above we would advocate for the removal of Simple BBCs being part of the scope of the Operational Review.
Question 27 Do you agree it is appropriate to rely on the quantitative analysis of the costs and benefits of the adjustment event proposals and a qualitative evaluation of the costs and benefits of the housekeeping proposals? If not, what information and evidence can you	Yes.

Question	Lodestone Response
provide, and what methods would you recommend, to quantify the costs and benefits?	
Question 28 Do you agree the benefits of the proposals can reasonably be expected to outweigh their costs?	Yes – to the extent that it will likely reduce Transpower administrative costs. We do not necessarily see that these changes will result in tangible benefits to those parties paying the BBCs.
Question 29 Do you agree that the preferred options will comply with section 32(1) of the Act?	We believe a key benefit to consumers would be the rapid facilitation of electrification, supplied by wide-spread use of distributed generation and energy storage technologies and removal of barriers to investment. To the extent that the review is constrained by Section 32(1) we do not believe the objectives of Section 15(1) is being achieved. In our view, the proposed measures are relatively incremental and therefore will have a limited impact on addressing some of the underlying structural issues with TPM. There is a risk that, without more substantive change, the status quo market dominance of the large gentailers will persist, which could continue to constrain the growth of smaller independent generators and retailers and, in turn, limit the potential for increased competition and long-term benefits for consumers.

Kind regards

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