TRANSPOWER

Consultation Summary on TPM Operational Review 2026 Workstream 1

30 March 2026

TPM Operational Review 2026

Consultation on Workstream 1 of the Transmission Pricing Methodology (TPM) Operational Review: Summary of Submissions

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Contact

For any enquiries regarding this document, please contact:

Name:	Victoria Parker
Position:	Head of Grid Pricing
Email:	TPMReview@transpower.co.nz

Purpose

The purpose of this document is to summarise the submissions received in response to the consultation on Workstream 1 of the Transmission Pricing Methodology (TPM) Operational Review 2026 (Operational Review).

Workstream 1 overview

Workstream 1 focuses on targeted, operational 'quick wins' to improve the workability of the TPM, reduce volatility and administrative burden, and discuss emerging issues.

The consultation paper sought feedback on the following proposals:

1. **Batching adjustment events**

Certain events trigger adjustments to benefit-based charges (BBCs) during a pricing year. For example, when large plant connects, disconnects, or materially changes output or load. Transpower considers the current settings create excessive volatility, administrative burden, and uncertainty for customers due to frequent intra-year changes.

The consultation paper sought feedback on a proposal to batch adjustments by treating most adjustment events as occurring on 30 June and processing them simultaneously for the following pricing year.

2. **Triggers/thresholds for adjustment events**

In addition to batching adjustments, the consultation paper sought feedback on either:

- increasing the threshold for what constitutes "large" plant under the TPM (so reducing their number); or

- introducing annual intra-regional allocator (IRA) updates, replacing several adjustment events (large plant connected/disconnected, substantial sustained increase, changed point of connection) with a once-a-year recalculation of IRAs.

3. **Removing substantial sustained increase (SSI) events**

The consultation paper sought feedback on removing the substantial sustained increase (SSI) adjustment event on the basis that it is unworkable in practice, relies heavily on customer self-reporting, and adds complexity and uncertainty.

4. **Housekeeping**

The consultation sought feedback on a package of proposed housekeeping amendments, including to extend the current simple method period to the end of PY2029 (or PY2030 if required) and removing drafting that is now redundant from the TPM.

5. **Emerging issues**

The consultation paper sought early feedback on whether and how certain issues relating to connection charges and first mover disadvantage (FMD) should be addressed. Our view in the consultation was that these matters raise broader policy issues that may be better referred to the Authority, and some potential solutions may not be fully consistent with the intent of the TPM Guidelines. We sought feedback from respondents as to how best to approach these issues:

These issues included:

- increases in connection charges for remaining customers when a customer disconnects from a shared connection location;
- the FMD Type 2 mechanism not applying to anticipatory investment in interconnection assets, resulting in existing customers funding investments intended to enable future connections; and
- limitations in the FMD Type 1 mechanism, including its non-application to embedded large plant and the absence of protection for first movers where subsequent connections do not occur.

Consultation process

The consultation period ran from Tuesday 3 March 2026, until Friday 20 March 2026.

There was no cross-submission stage due to the technical nature of the Workstream 1 amendments, as well as the timing constraints for the changes to be implemented for the next pricing year (1 April 2027 – 31 March 2028).

Next steps

We are now considering feedback and expect to decide on potential Code change proposals under Workstream 1 shortly. These will be shared with the TPM Industry Working Group before our proposals are submitted to the Electricity Authority (Authority) in early April for their consideration.

We will also consider the best way forward in relation to the emerging connection charge and FMD issues (described in more detail below), but they will not form part of any proposed TPM amendments at this stage.

In parallel, we are preparing for the next phase of the Operational Review —Workstreams 2 and 3 — which is expected to begin around mid-year. These workstreams will review the Benefit-Based Charges (BBCs) Simple and Standard Methods. We'll let you know more information about these workstreams closer to the time.

Feedback received

Transpower received feedback from 13 stakeholder organisations, which are available on our website.

Electricity Distributors (6)	Electricity generators (5)	Consumers/other (2)
EA Networks	Contact Energy	Fonterra
Electricity Networks Aotearoa (ENA)	Genesis Energy	Major Electricity Users Group (MEUG)
Orion	Independent Electricity Generators Association (IEGA)	
Unison and Centralines	Lodestone Energy	
Vector	Meridian Energy	
Westpower		

We appreciate the feedback we received. Stakeholder input is valuable and will help inform the development of any changes we will propose to the Electricity Authority.

Support for the Operational Review

Submissions were broadly supportive of Transpower undertaking an operational review and our stakeholder engagement process, and acknowledged the administrative challenges created by the current TPM. A number of submitters emphasised that their support for the Workstream 1 proposals was limited, qualified, or contingent on further reform e.g. raising wider concerns about the efficacy of a benefit-based TPM. Several submitters considered that the proposals address symptoms rather than underlying structural issues with the TPM and that larger changes are needed than the incremental reforms expected as part of the Operational Review.

Electricity Networks Aotearoa (ENA) "appreciates the opportunity to provide feedback and acknowledges Transpower's willingness to consult on these proposals". Fonterra welcomed Transpower's engagement but noted that, "in its view, the scope of the review should be widened to include policy level analysis to confirm whether the TPM is delivering the outcomes originally intended".

Major Energy Users Group (MEUG) noted that it "welcomes Transpower commencing this operational review of the current Transmission Pricing Methodology (TPM) and the establishment of the TPM operational review working group, to bring together expertise and insights from across the sector. We have been open about our serious concerns with the TPM, as members and businesses across the country continue to face increases in transmission charges, yet with less transparency and predictability of how these charges are allocated."

Unison and Centralines, in a joint submission, "appreciate Transpower's continued engagement with industry participants as part of the TPM Operational Review."

Orion "supports the proposed Operational Review workstreams."

Fast-tracking the opportunity for 'quick wins'

Overall, there was positive support for the process Transpower is adopting for the Operational Review, including the staged approach and prioritisation of 'quick wins'.

There were, however, concerns that, given the technical complexity of the proposals and their potential financial impacts, the consultation for Workstream 1 was too short and this compromised the extent to which stakeholders could adequately respond to the proposals.

Meridian noted that it "appreciate[s] that Transpower is seeking to move at pace with Workstream 1 so that changes can be adopted for the pricing year commencing 1 April 2027. However, we would note the obvious point that any change to the TPM is generally complex and it would be beneficial to provide sufficient time for stakeholders to consider these issues thoroughly."

ENA echoed this point, noting that "consultation timeframes should be longer for such complex and consequential issues."

Vector "support[s] Transpower's approach to prioritise "quick wins" in the first stage of its operational review as a pragmatic approach to the review."

Westpower "supports the Operational Review and agrees with the prioritisation of Workstream 1 as focusing on practical quick wins. … We also support Transpower's staged approach, but it is vital that the Authority ultimately revisits whether the TPM is delivering fair and efficient outcomes for regional consumers."

Support for amendments to simplify the TPM and create greater price stability

Submitters were also supportive of the overall objectives of the Operational Review, with the qualification, echoed by multiple submitters, that are more fundamental issues with the TPM that need to be addressed and cannot be resolved through incremental changes.[1]

ENA "supports efforts to improve the operational workability of the TPM and reduce unnecessary volatility and administrative burden." They noted that "EDBs have consistently highlighted that the TPM can be difficult to interpret and administer and that frequent adjustments create uncertainty for network planning and for communicating transmission costs to consumers. Measures that improve workability and predictability are therefore welcome."

Unison and Centralines "consider the proposed operational changes represent pragmatic improvements that should enhance the usability, predictability, and administrative workability of the TPM. These refinements have the potential to reduce unnecessary complexity and regulatory transaction costs while maintaining the core objectives of the framework."

Efficient price signals

A number of submissions emphasised the importance that changes to the TPM made as part of the Operational Review don't harm efficient price signals/create distortionary pricing signals.

ENA and Westpower, for example, both emphasised "that operational changes must not unduly undermine efficient price signals, particularly where the TPM is intended to support efficient

[1] See commentary under "Wider concerns with the TPM".

investment decisions for generation, load, and electrification." ENA went on to say this includes that “delays in adjustments do not materially distort cost allocation signals” and that the “large” plant “threshold should be calibrated carefully to ensure it does not weaken locational signals or create incentives for inefficient plant sizing or location decisions.”

Unison and Centralines cautioned that “In progressing these operational improvements, it remains important that the TPM continues to provide cost-reflective and neutral pricing signals across the transmission-distribution interface, supporting efficient whole-of-system outcomes” and that “Adjustments to threshold settings should be designed to preserve effective pricing signals and avoid creating incentives for embedded generation or load to connect at the distribution level primarily to circumvent transmission charges.”

Orion also cautioned that “any batching approach should ensure that significant changes in grid use are still reflected in transmission prices within a reasonable timeframe and that price signals remain broadly cost-reflective” and the cost benefit analysis (CBA) should consider “wider impacts on investment signals, pricing accuracy, or long-term efficiency outcomes.”

Other submissions also raised concerns that the current TPM does not provide efficient price signals.[2]

Matters that are out-of-scope

Some submissions raised options outside of the scope of the TPM, including for both Operational Reviews and Authority reviews.

This included, for example, the following suggestions from Lodestone:

- options for revaluation of connection assets where the difference in value would “be a loss in asset value to the Shareholder”; and
- (for the FMD Type 1 mechanism) that “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)”.

We consider these to be matters that fall under the jurisdiction of the Commerce Commission under Part 4 Commerce Act and therefore will not be considered by Transpower in the context of the Operational Review.

Summary of stakeholder views on proposed TPM amendments

There was support across the submissions for our proposed Workstream 1 amendments.

Where stakeholders particularly differed in view was in relation to:

- whether the “large” plant threshold should be increased or the IRA should be updated annually. Submitters that supported an increase in the “large” plant threshold supported a 25MW threshold as a minimum

[2] See the discussion on “Wider concerns”.

- Contact opposed increasing the “large” threshold, expressing concern that the change could cause boundary issues and subsequent distortions to arise from the TPM, encouraging inefficient embedding of generation

- Genesis and Meridian raised concerns about the proposal to update the IRA. Meridian considered that updating the IRA was a matter the Authority should consider on the basis that such a change would have pervasive implications

- Meridian was the sole dissenter to the proposal to extend the simple method period.

Views were mixed about whether the emerging matters of disconnection from shared connection location, anticipatory investment in interconnection assets and FMD problems, and the FMD Type 1 mechanism for connection assets that benefit embedded large plants, should be dealt with through the Operational Review or by the Authority. However, there was general agreement that they were matters that needed to be addressed.

Batching of adjustments with a deemed 30 June event date

All submitters that responded to this question supported batching of adjustment events, although several did so on a qualified basis: Contact, ENA (with design caveats), Genesis (qualified[3]), IEGA, Lodestone (noting, however, the limited benefits for Distributed Generation (DG)), MEUG, Orion, Unison and Centralines, Vector and Westpower.

This was the only change that Contact explicitly supported in Workstream 1.

Increasing the “large” plant threshold

The option to increase the “large” plant threshold was supported by IEGA, Lodestone (“in principle”), Vector (qualified) and Westpower.

Contact did not support the proposal, raising concerns with the proposal relating to, among other things, boundary effects and cross-subsidisation. Genesis raised a number of risks, including cross subsidies from existing customers to new embedded generators and erosion of the beneficiary-pays principle.

If Transpower proposed raising the threshold for “large plant”, what threshold(s) do you consider would be appropriate?

Submitters that responded to this question supported a threshold of 25MW (Unison and Centralines, Orion, Vector (qualified as “in principle”) and Westpower) or 25MW or more (Lodestone and MEUG).

Lodestone considered that a threshold of “between 25 to 40 MWAC [alternating current] would be appropriate. This would go a long way to encouraging more distributed generation and energy storage.”

[3] “Transpower should consider how the proposal to batch adjustment events may have unintended consequences. Specifically, the proposal would seem to mean customers who connect early in a pricing year will not pay increased (adjusted) benefit-based charges for up to a year i.e. until the new pricing year takes effect with the adjusted benefit-based charges.”

Annual IRA updates

The option for annual IRA updates was supported by EA Networks, ENA (with caveats), Meridian (“tentatively”), Orion, and Vector (“in principle” support only).

Genesis and Meridian both raised concerns about annual IRA updates. Meridian “question[ed] whether such a change should be progressed through an Operational Review,” while Genesis raised concerns about boundary effects, cross-subsidisation and potential distortions to cost allocation.

Amending the TPM 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?

The submitters that responded to this question supported the amendment to remove SSI adjustment events, being ENA, IEGA, Lodestone, MEUG, Orion, Unison and Centralines, Vector and Westpower.

Extending the first simple method period to the end of PY2029 or to the end of PY2030 if required

This proposal was supported by ENA, IEGA, MEUG, Orion, Unison and Centralines, Vector and Westpower.

Meridian was the only submitter that objected to the proposal.

Clean up of the TPM legal text

The submitters that responded to this question all supported the proposal: ENA (qualified[4]), IEGA, Lodestone, Meridian, MEUG, Orion, Unison and Centralines, Vector and Westpower.

Emerging issues

While many submitters agreed that the emerging connection charge and FMD issues identified by Transpower are real and potentially material, views were mixed on whether these matters should be addressed through the Operational Review or instead referred to the Authority for broader policy consideration.

In more detail:

- ***Disconnection from shared connection location***

  There were mixed views about whether this matter should be dealt with through the Operational Review.

  Genesis, Lodestone, Orion and Westpower all submitted that this matter should be addressed through the Operational Review.

  ENA, Meridian and MEUG alternatively suggested that this was a matter more appropriately dealt with by the Authority.

[4] “ENA agrees in principle but has not had time to review the specific proposed changes.”

- ***Anticipatory investment in interconnection assets and FMD problems***

  ENA (qualified[5]), Lodestone, Orion and Westpower all submitted that this is a matter that should be addressed through the Operational Review.

  Meridian had an opposing view, raising the concern that the "emerging issues identified are substantive" and thought the issue is "best referred to the Electricity Authority for consideration."

- ***The FMD Type 1 mechanism for connection assets that benefit embedded large plants***

  Lodestone thought this matter should be addressed through the Operational Review.

  IEGA, MEUG, Meridian and Vector alternatively considered this to be a matter which should be addressed by the Authority.

Wider concerns: TPM design

Some submissions highlighted dissatisfaction with the fundamental design of the TPM and raised concerns that are beyond the scope of the Operational Review. This included concerns that while the incremental changes proposed as part of the Operational Review process may be beneficial, they do not address the more fundamental, structural problems with the TPM.

Contact submitted "… the TPM is fundamentally flawed" and "The issues with the TPM are deep-seated and fundamental." Contact suggested "the minor tweaks that Transpower is proposing will only need to be reworked again in future if/when the real issues with the TPM are addressed."

Lodestone similarly submitted that "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."

Fonterra, Genesis and MEUG also referenced the Post-Implementation Review findings. MEUG submitted that "the Concept Consulting post-implementation review report succinctly captures the concerns raised by a broad range of stakeholders."

Fonterra submitted that "since the TPM was implemented the level of complexity and uncertainty around transmission pricing has been high, and the projected savings have not appeared" and suggested "the TPM review scope should be wider to the point of a looking at policy related analysis to confirm that it is delivering what was expected when the changes were approved as indicated in the Concept Consulting post-implementation review."

Wider concerns: benefit-based charges (BBCs)

Westpower submitted that "the BBC process is not working as intended and undermines affordability for regional consumers and confidence in the methodology."

[5] "Potentially, but it is important to stay connected to existing workstreams in the sector that are also considering this problem."

Lodestone submitted:

> *"We … 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.*
>
> *"… 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.*
>
> *"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."*

Wider concerns: Lack of peak-usage charges

One of the issues that was raised was the lack of a peak-usage pricing signal following the removal of the old regional coincident peak demand-based interconnection charge. This is an issue that has been consistently raised by a large number of stakeholders, including in response to Authority distribution pricing consultations and in relation to the energy transition as a whole.

Vector submitted that "we consider the current system lacks a price signal for long run marginal costs in the transmission network. Future transmission costs are not signalled in either distribution pricing or in the TPM. Retailers, and consumers, therefore have no visibility of this information when developing products and considering investment and operational / consumption decisions. An appropriate price signal could assist market co-ordination on solutions that could defer the need for investment."

Westpower submitted that "the Regional Coincident Peak Demand (RCPD) … previously provided important peak usage signals, encouraging incentives to manage demand during system peaks." Commenting on its removal, they said "this decision has removed a key tool to encourage consumers to change their peak usage away from times where the grid is constrained and excessive wholesale peak pricing is incurred."

Appendix A: Summary of responses to questions

Q#	Topic	Overall level of support	Key submitters	Main points raised
1	**Process, timing and prioritisation**	Broad support with concerns	MEUG, Orion, Vector, Westpower (support); ENA, Meridian, Orion (concerns)	Staged approach and focus on ‘quick wins’ supported; consultation timeframe considered too short for complex material.
2	**Other matters to consider**	Mixed	Lodestone, Westpower	Raised broader issues (remote EDB impacts, BBC robustness, Simple BBIs) that may sit outside the scope of the Operational Review.
3	**Matters to exclude**	Limited response	Vector	Fundamental policy changes not appropriate for an Operational Review.
4	**Batching adjustment events (30 June deemed date)**	Unanimous support	Contact, ENA, Genesis (qualified), IEGA, Lodestone, MEUG, Orion, Unison & Centralines, Vector, Westpower	Improves predictability; reduces admin burden; avoids repeated in-year price changes.
5	**Other timing simplification options**	Limited but supportive	ENA	Supported reducing frequency of in-year adjustments; suggested annual recalibration options e.g. IRA.
6	**Increase large plant threshold vs annual IRA updates**	Mixed but broadly supportive	IEGA, Lodestone, Vector, Westpower (threshold); EA Networks, ENA, Meridian (tentative), Orion, Vector (IRA)	Threshold reduces adjustment events; annual IRAs reduce distortions; generators raised embedding incentives.
7	**Appropriate large plant threshold**	Strong majority support	Unison & Centralines, Orion, Vector, Westpower (25MW); Lodestone, MEUG (25–40MW); ENA (qualified)	10MW seen as too low; higher threshold reduces admin burden.
8	**Other trigger/threshold options**	No responses	–	–
9	**Removing SSI adjustment events**	Majority support	ENA, IEGA, Lodestone, MEUG, Orion, Unison & Centralines, Vector, Westpower	SSI difficult to implement; poor data; subjective judgement.
10	**Other options to improve adjustment event workability**	Limited response	Westpower	BBC calculations complex relative to <10% revenue contribution.

11	**CBA approach and assumptions**	Mixed	Vector (supportive); ENA, Orion (critical); Westpower (costs understated)	CBA too focused on transaction costs; wider investment and efficiency impacts not captured.
12	**Extend first simple method period**	Strong majority support	ENA, IEGA, MEUG, Orion, Unison & Centralines, Vector, Westpower	Resource constraints justify extension; stability valued.
12	**Objection to extension**	Minority opposition	Meridian	Regular NPB updates important; resourcing not a TPM issue.
13	**Options for second simple method period**	Limited feedback	Lodestone, Westpower	Suggested removing Simple BBIs from BBCs; BBC too complex.
14	**Clean up TPM legal text**	Unanimous support	ENA (qualified), IEGA, Lodestone, Meridian, MEUG, Orion, Unison & Centralines, Vector, Westpower	Improves clarity, usability, and consistency.
15	**Other legal clean-up opportunities**	No responses	–	–
16	**Disconnection from shared connection locations**	Unanimous agreement it is a problem	Contact, ENA, Genesis, IEGA, Lodestone, MEUG, Orion, Vector, Westpower	Inequitable cost impacts; risk of “death spiral.”
17	**Options to address disconnection issue**	Mixed but aligned	IEGA, Lodestone, Vector, Westpower	Favoured broader cost sharing or asset revaluation approaches.
18	**Should disconnection issue be addressed via operational review**	Mixed	Genesis, Lodestone, Orion, Westpower (yes); ENA, Meridian, MEUG (Authority)	Split on appropriate forum.
19	**First mover disadvantage (FMD)**	Consensus it is a problem	Contact, ENA, Genesis, Lodestone, Orion, Vector, Westpower	TPM seen as barrier to anticipatory investment.
20	**Options to address FMD**	Limited but consistent	ENA, Genesis, Lodestone, Westpower	Broader cost sharing; temporary socialisation; residual charge use.
21	**Should FMD be addressed via operational review**	Mixed	ENA (qualified), Lodestone, Orion, Westpower (yes); Meridian (Authority)	Differing views on scope.
22	**Allocation of FMD Type 1 risk**	Limited responses	ENA, Lodestone, Westpower	Risk should not sit solely with first mover or load customers.

23	**FMD Type 1 and embedded large plants**	Very limited response	Lodestone	Fairness depends on connection sequencing.
24	**Options for FMD Type 1**	Limited response	ENA	Existing generators benefit from delayed connections.
25	**Should FMD Type 1 be addressed via operational review**	Mixed	Lodestone (yes); IEGA, MEUG, Meridian, Vector (Authority)	Majority preference for Authority to lead.
26	**Overall objectives of the operational review**	Broad support	ENA, Unison & Centralines, Vector, Lodestone, Orion, Westpower	Improvements to predictability and workability welcomed.
27	**Quantitative vs qualitative assessment**	Mixed	Lodestone, Vector, Westpower (support); ENA, Orion (concerned)	Qualitative acceptable for housekeeping; evidence limited.
28	**Do benefits outweigh costs**	Limited but supportive	Lodestone, Vector, Westpower	Reduced volatility and admin burden material.
29	**Compliance with s32(1) of the Act**	Limited but supportive	Vector, Westpower	Preferred options consistent with Act.

Appendix B: Responses to consultation questions

Question 1 Do you have any comments on the process, timing and/or prioritisation of each of the Operational Review workstreams?

There was positive support for the process Transpower has adopted, including the staged approach and prioritisation of ‘quick wins’. There were some concerns that the consultation for the first stage of the OpRev26 was too short and this compromised the extent to which stakeholders could respond.

Process

MEUG “… are comfortable with the proposed plan of work put forward by Transpower, with the use of legal advice and cost benefit analysis to support the changes.”

Orion “… supports the proposed Operational Review workstreams and timeline”.

Westpower “support Transpower’s staged approach, but it is vital that the Authority ultimately revisits whether the TPM is delivering fair and efficient outcomes for regional consumers.”

Timeframe for the consultation

ENA, Meridian and Orion raised concerns about the short timeframe of the consultation.

ENA were “concerned that the consultation period has been too short given the complexity and importance of the TPM framework. … A short consultation window limits the ability of EDBs to fully assess impacts, coordinate industry views, and provide robust evidence-based feedback.”

Orion similarly commented that “The timeframe provided for submission has not been sufficient to robustly analyse the material including cost benefit analysis and Code drafting or appropriately understand all implications of changes.”

Meridian “appreciate[d] that Transpower is seeking to move at pace with Workstream 1 so that changes can be adopted for the pricing year commencing 1 April 2027” but felt that “it would be beneficial to provide sufficient time for stakeholders to consider these issues thoroughly” and recommended that “Going forward” the consultation period should be 4-6 weeks “to accommodate this.”

Prioritisation

Vector “… support Transpower’s approach to prioritise “quick wins” in the first stage of its operational review as a pragmatic approach to the review.”

Westpower similarly “… supports the Operational Review and agrees with the prioritisation of Workstream 1 as focusing on practical quick wins.”

Question 2 Are there any other matters that we should consider as part of the Operational Review?

Lodestone submitted that:

> "We think the fundamental TPM policy should be within scope of this review. …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."

Westpower submitted that:

> "… the Operational Review should explicitly consider the disproportionate impact the TPM has had on remote EDBs" and that "… The other issue with the TPM and the proposed major capital investment in the Upper South Island is that regional EDB's will incur ongoing higher transmission costs, even though a number of EDB's in the region do not require additional capacity, and will receive no benefit. These EDB's will essentially be providing a cross-subsidy to other EDB's who do require additional capacity."

Question 3 Are there any matters we should specifically exclude from the Operational Review?

Vector was the only submitter that responded to this question. Vector agreed "…fundamental policy changes are not appropriate to be considered as part of an operational review."

Question 4 Do you agree with the proposed amendment - batching of adjustments with a deemed 30 June event date?

The batching proposal had consensus support. All submitters that responded to this question supported batching: Contact, ENA (with design caveats), Genesis (qualified[6]), IEGA, Lodestone (noting, however, the limited benefits for Distributed Generation (DG)), MEUG, Orion, Unison and Centralines, Vector and Westpower.

ENA, for example, "… sees merit in batching adjustment events where this improves predictability of transmission charges and reduces administrative burden for both Transpower and customers. Frequent in-year adjustments create practical challenges for EDBs when forecasting costs and communicating transmission charges to downstream customers."

Unison and Centralines submitted that "Under the current framework, adjustment events may occur multiple times within a pricing year. This can create administrative complexity and make it difficult for distributors to incorporate transmission charges into annual pricing."

[6] "Transpower should consider how the proposal to batch adjustment events may have unintended consequences. Specifically, the proposal would seem to mean customers who connect early in a pricing year will not pay increased (adjusted) benefit-based charges for up to a year i.e. until the new pricing year takes effect with the adjusted benefit-based charges."

Question 5 Are there any other options to simplify adjustment events timing that we should consider?

ENA was the only submitter to respond to this question: “ENA supports further exploration of mechanisms that reduce the frequency of in-year adjustments while maintaining efficient pricing signals. This includes, but is not limited to, further analysis of the Intra-Regional Allocator (IRA) proposal. Annual recalibration of certain parameters may be one option where this reduces administrative complexity without materially distorting cost allocation outcomes.”

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?

“Large” plant threshold

The option to increase the “large” plant threshold was supported by IEGA, Lodestone (“in principle”), Vector (qualified as “in principle”) and Westpower.

Westpower, for example, submitted “The existing 10MW threshold is too low and has resulted in unnecessary adjustment events, particularly for embedded plant that has no realistic prospect of connecting directly to the grid.”

Contact, on the other hand, “… oppose the proposal to increase the ‘large plant’ threshold” on the basis that “This change would cause boundary issues, and subsequent distortions to arise from the TPM, likely encouraging inefficient embedding of generation. The issue arises because (predominantly embedded) generation that is below the threshold is treated differently to other generation (net versus gross) for charge calculations.”

Annual IRA updates

The option for annual IRA updates was supported by EA Networks, ENA (with caveats), Meridian (“tentatively”), Orion, and Vector (“in principle” support only).

EA Networks submitted:

> “Annual IRA updates would:
> • Ensure charges evolve over time to better reflect actual use of the grid.
> • Enable reverse-engineering of changes in IRA to identify the contribution of individual embedded generators or load changes.”

ENA submitted that “We generally support moving to annual IRA updates, as this change would materially reduce these distortions. However, ENA is open to further discussion on the relative merits of increasing thresholds versus adopting annual IRA updates, as we feel that the current consultation paper provides insufficient detail on how this would work and the relative costs and benefits of such an approach. This is resulting in some differences of opinion amongst EDBs.”

Genesis and Meridian raised concerns about the proposal.

Genesis raised concern that while “We agree with comments by the IWG to the effect that option 1 would likely incentivise embedded generation, and that this could likely be distortionary and inefficient … we think option 2 could still have the same impact i.e. it would still incentivise embedded generation over grid-tied generation.” Meridian similarly submitted that “We agree with the Industry Working Group that Option 3 (Replace BBC adjustment events with an annual Intra-Regional Allocator and customer allocation) would be a bolder change with more pervasive implications. As such, we question whether such a change should be progressed through an Operational Review."

Question 7 If Transpower proposed raising the threshold for "large plant", what threshold(s) do you consider would be appropriate?

Submitters that responded to this question supported 25MW (Unison and Centralines, Orion, Vector and Westpower) or 25MW or more (Lodestone and MEUG). Lodestone considers that a threshold "Between 25 to 40 MWAC would be appropriate. This would go a long way to encouraging more distributed generation and energy storage." MEUG submitted that it should be "at least 25 MW".

ENA submitted that "… a higher threshold may be appropriate if the current threshold is driving excessive adjustment events. However, the appropriate level should be informed by further analysis of how different thresholds affect investment signals, adjustment event frequency, and overall price accuracy."

Unison and Centralines submitted that "Increasing the threshold should help reduce the number of adjustment events, improve the operational workability of the TPM, and reduce administrative burden for both Transpower and transmission customers."

Question 8 Are there any other options to address trigger/threshold sensitivity we should consider?

There were no responses to this question.

Question 9 Do you agree with our initial view that the TPM should be amended to:
o remove the SSI adjustment events;
o clarify how Transpower should treat staged projects by adding time and certainty constraints;
o remove all embedded adjustment events and SSI; and/or
o switch to annual review of IRAs and remove most of the adjustment events?

This proposed amendment to remove SSI adjustment events had majority support. The submitters that responded to this question supported this proposal: ENA, IEGA, Lodestone, MEUG, Orion, Unison and Centralines, Vector and Westpower.

ENA "… sees potential merit in removing SSI adjustment events if other mechanisms adequately capture material changes in grid use over time."

Unison and Centralines similarly submitted "We support Transpower's proposal to remove SSI adjustment events. In practice, these adjustment events appear difficult to implement due to limited access to reliable consumption and generation data, reliance on customer self-reporting, and the need for subjective judgement. Removing these adjustments should improve the workability and transparency of the TPM while reducing unnecessary administrative complexity."

Question 10 Are there any other options that we should consider to improve adjustment event workability?

Westpower was the only submitter that responded to this question: "The extremely complicated calculations to produce the BBC income seems unnecessary when BBC accounts for less than 10% of revenue. Workability could be improved by less emphasis on these calculations."

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) b) c) 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?
Does the effect adjustment events have on businesses:
I. alter or delay investment commitment for embedded 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?
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?

ENA submitted that it "…considers the current CBA to be too limited to support robust evaluation of the proposals. The analysis focuses primarily on transaction costs and does not capture wider impacts on investment signals, pricing accuracy, or long-term efficiency outcomes."

Orion similarly submitted that it "… considers … the current CBA to be too limited to support robust evaluation of the proposals. The analysis focuses primarily on transaction costs and does not capture wider impacts on investment signals, pricing accuracy, or long-term efficiency outcomes."

Vector submitted "We agree the benefits of the proposal are likely to outweigh the costs given the administrative burden and uncertainty created by current provisions. … Engagement costs vary by event, but an average assumption of $5,000 per adjustment appears reasonable."

Westpower submitted "It [the CBA] completely understates costs for smaller EDBs, including management time, forecasting effort, retailer engagement and customer communication. This needs to be revisited."

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?

This option has majority support from ENA, IEGA, MEUG, Orion, Unison and Centralines, Vector and Westpower.

Vector, for example, submitted that "this is a pragmatic approach that avoids duplication and reduces administrative burden."

Meridian was the only submitter that objected to the proposal.

Meridian submitted that "… this is a resourcing issue rather than an issue with the TPM. Maintaining a regular update cycle for recalculating the net private benefits (NPBs) to determine simple method allocations is an important part of maintaining TPM charges which reflect the NPBs of individual payers. We encourage Transpower to stick to the current codified schedule for the second simple method period."

Question 13 Are there any other options we should consider for the second simple method period work?

Lodestone submitted that "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."

Westpower submitted that the "BBC is too complicated for the benefit it produces and could be simplified even more for better understanding".

Question 14 Do you agree with the proposal to clean up the TPM legal text?

This option had strong majority support. The submitters that responded to this question all supported the proposal: ENA (qualified[7]), IEGA, Lodestone, Meridian, MEUG, Orion, Unison and Centralines, Vector and Westpower.

MEUG submitted, for example, that "We fully support Transpower undertaking a general clean-up of the TPM legal text to remove redundant and outdated clauses and make some changes for clarity and to correct typographical errors."

Unison and Centralines submitted "These changes should help improve the clarity, consistency, and usability of the TPM."

Question 15 Are there any other opportunities to clean up the TPM legal text we have not identified?

There were no submissions in response to this question.

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?

The submitters that responded to this question all agreed this was a problem: Contact, ENA, Genesis, IEGA, Lodestone, MEUG, Orion, Vector and Westpower.

ENA, for example, submitted that "EDBs are concerned that disconnection from shared connection locations may lead to increased costs for remaining customers, potentially creating inequitable outcomes. As electrification and distributed generation increase, these situations may become more common and warrant further policy consideration."

[7] "ENA agrees in principle but has not had time to review the specific proposed changes."

Genesis submitted "We agree with Transpower and the IWG that 'lumping' the entirety of costs onto remaining customers at a shared location is inefficient and inconsistent with cost reflective pricing principles …"

Lodestone submitted that "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."

MEUG submitted "We agree with Transpower's position that "it is not efficient for a subset of connection customers to bear this disconnection risk," and that other options need to be explored for managing the costs over a broader group of customers. We need to avoid the risk of a "death spiral" occurring. This is a concept talked about particularly in the gas sector, where an increasingly shrinking group of customers is required to cover fixed costs. As individual costs increase substantially for the remaining customers, more continue to disconnect, leaving very few to cover the full cost of the network."

Orion "agrees that disconnection from a shared connection location creates a problem for remaining customers at that location. As an EDB we recognise that our load customers (mass market) will often be the bearer of these 'hand me down' costs where no conscious investment decision by these customers brings the additional costs upon them. As differing customers connection to GXPs, including generators, and economic situations change we believe this could be become a material problem."

Question 17 What other options do you think should be considered? Are these options consistent with the intent of the TPM Guidelines?

The options raised by submitters tended to be in relation to broadening the customer base from which the costs are recovered.

IEGA submitted that "The IEGA supports further investigation of options to address the impact of disconnection on remaining customers to a connection asset. Transpower must be required to review the valuation of a connection asset after a customer disconnects. We note that the TPM has a process for reassignment of interconnection assets which includes consideration of the impact on asset value."

Lodestone submitted "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."[8]

Vector submitted "We consider the unrecovered connection charges should be recovered from the broadest possible customer base to minimise the impact on individual customers.

Westpower submitted "Westpower supports spreading this risk across a wider customer base rather than leaving it with the remaining customers at the shared connection location.

"In our view it would be preferable to include these unrecovered charges through connection charges rather than the residual charge to avoid lumping all unrecovered connection charges solely on load."

[8] See section on "Matters that are out-of-scope".

Question 18 Do you think that this is a matter that could/should be addressed through the Operational Review?

Genesis, Lodestone, Orion and Westpower submitted that this matter should be addressed through the Operational Review. ENA, Meridian and MEUG thought it should be addressed by the Electricity Authority.

Genesis, for example, submitted that "… there may be merit in Transpower and the Authority considering this issue via the Operational Review." Orion similarly submitted: "the matter of disconnection from a shared connection location should be addressed through the operational review."

Meridian alternatively "… agree with Transpower this is likely to raise policy matters more appropriately dealt with by the Authority."

"Meridian's view is that each of the three emerging issues identified are substantive and that some of the options canvassed may be outside of the intent of the existing TPM Guidelines. We therefore agree with Transpower that each of these issues are best referred to the Electricity Authority for consideration."

MEUG similarly "…recommend that this issue is elevated up to the Authority, so that it can begin exploring options for addressing this issue within the next year." Likewise, ENA submitted "We recommend that this issue is elevated up to the Authority, so that it can begin exploring options for addressing this issue within the next year. Modelling of different options will help determine what is the best approach for consumers overall, and what Code amendments may be required to enable the necessary changes."

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?

The submitters that responded to this question agreed anticipatory investment in interconnection assets can create FMD problems: Contact, ENA, Genesis, Lodestone, Orion, Vector and Westpower.

Contact, for example, submitted: "we … see the current TPM as being a major impediment to anticipatory investment. The Tararua anticipatory investment example highlights that the status quo is untenable. The Tararua anticipatory investment (even if it were a good idea3) cannot proceed under the current TPM because the ensuing allocation of costs would be highly inequitable and politically untenable."

Genesis submitted that they have "directly experienced first-mover disadvantage and the "free-rider" problem. This can have a material impact on new generation connections, and it is therefore critical for Transpower and the Authority to address it. We also note a key source of uncertainty is the lack of visibility regarding future connections or disconnections."

Lodestone submitted "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?

ENA submitted "The Energy Framework have a workstream to consider alternative funding for anticipatory investment. We recommend Transpower stay connected with this work as the operational review continues. Within the time allowed, ENA is unable to comment on how easily the option could be implemented while maintaining consistency with the TPM Guidelines."

Genesis submitted "we would be in principle supportive of "no-regrets tactical fixes" that afford protection to existing regional load customers for anticipatory investments, provided these are net-beneficial, and align with the TPM policy intent."

Lodestone submitted "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."

Westpower submitted "Costs should be more broadly shared until future beneficiaries connect. Simplifying the calculations could be a start."

Question 21 Do you agree that this is a matter that could/should be addressed through the Operational Review?

ENA (qualified[9]), Lodestone, Orion and Westpower submitted that this is a matter that should be addressed through Operational Review.

Meridian had an opposing view raising concern that the "emerging issues identified are substantive" and though that the issue is "best referred to the Electricity Authority for consideration."

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?

ENA submitted "… the default position should not be to impose this risk on load customers alone. Existing generators benefit from delayed investment by other generation connections for whom transmission assets have been constructed, this benefit is realised through the increased system capacity and higher prices their generation can command through the spot market."

Lodestone submitted "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)."[10]

Westpower submitted that it "… considers the risk should not sit solely with the first mover."

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?

Lodestone was the only submitter to respond to this question:

> "Not necessarily.

[9] "Potentially, but it is important to stay connected to existing workstreams in the sector that are also considering this problem."
[10] See section on "Matters that are out-of-scope".

> "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?

ENA was the only submitter to respond to this question:

> "… the default position should not be to impose this risk on load customers alone. Existing generators benefit from delayed investment by other generation connections for whom transmission assets have been constructed, this benefit is realised through the increased system capacity and higher prices their generation can command through the spot market."

Question 25 Do you think these are matters that could/should be addressed through the Operational Review?

Lodestone thought this matter should be addressed through the Operational Review.

IEGA, MUEG, Meridian and Vector alternatively considered it to be a matter which should be addressed by the Authority.

IEGA "…support the Authority further investigating the wide range of options to socialise anticipatory interconnection investment costs arising due to anticipated generation investment."

MEUG "… recommend that this issue be conveyed to the Authority urgently and be set as a priority workstream to discuss with both Transpower and the Commerce Commission."

Vector "…expect this may raise policy matters that should be considered by the Authority."

Question 26 Do you agree with the overall objectives of the proposed TPM Operational Review?

Submitters were supportive of the overall objectives of the OpRev26, with the only qualification being that there were more fundamental issues that need to be addressed that cannot be resolved through incremental changes.[11]

ENA, Unison and Centralines, Vector, Lodestone, Orion and Westpower submitted in support.

ENA, for example, "broadly supports the objective of improving transparency, predictability, and workability of the TPM while maintaining efficient pricing signals. Simplifying operational aspects of the TPM could benefit both Transpower and transmission customers if implemented carefully."

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).

Unison and Centralines similarly submitted that they "consider the proposed operational changes represent pragmatic improvements that should enhance the usability, predictability, and

[11] See commentary under "Wider concerns with the TPM".

administrative workability of the TPM. These refinements have the potential to reduce unnecessary complexity and regulatory transaction costs while maintaining the core objectives of the framework."

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 provide, and what methods would you recommend, to quantify the costs and benefits?

Lodestone, Vector and Westpower explicitly supported the approach Transpower has adopted.

Vector, for example, submitted that "We agree it is appropriate to rely on a qualitative evaluation on the cost and benefits of the housekeeping proposals."

ENA and Orion raised concerns about whether the consultation included sufficient evidence.

ENA was concerned "there are areas of the consultation that lacked sufficient evidence to enable comprehensive assessment" and was also "concerned about the limited scope and robustness of the cost-benefit analysis (CBA) provided to support the adjustment event proposals. … the CBA explicitly excludes wider impacts such as changes to investment behaviour, pricing accuracy, or long-term efficiency outcomes because these are difficult to quantify."

Orion felt that they did not have "sufficient time to carefully consider and evaluate Transpower's analysis" and were "concerned about the limited scope and robustness of the cost benefit analysis (CBA) provided to support the adjustment event proposals. Accordingly, we are unable to conclude on the appropriateness of the CBA."

Question 28 Do you agree the benefits of the proposals can reasonably be expected to outweigh their costs?

Lodestone, Vector and Westpower responded to this question. They all agreed.

Westpower submitted that "The benefits certainly outweigh the understanding and hence the costs. Reducing volatility, administrative burden and uncertainty will materially benefit small EDBs and their consumers."

Question 29 Do you agree that the preferred options will comply with section 32(1) of the Act?

Vector and Westpower responded to this question. They both agreed the preferred options will comply with section 32(1) of the Electricity Industry Act.