Transmission pricing methodology amendments: a level playing field for emerging technologies

Consultation paper

5 August 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (the Authority) adopted a new transmission pricing methodology (TPM) in April 2023. This new TPM better supports the electrification of the economy and paves the way for new and emerging technologies. The Authority expects the resulting new robust and efficient transmission pricing will bring substantial benefits to consumers in the years ahead.

This paper sets out a further opportunity to improve the functionality of the TPM so it better encourages efficient investment and use of the grid. In the course of setting transmission charges for new Battery Energy Storage Systems (BESS) connecting to the grid, two issues have been identified with the way charges are allocated under the TPM. The materiality of these issues has become apparent now due to detailed modelling recently provided to the Authority. The current allocation rules will result in BESS and some other customers paying disproportionately high charges and cause perverse incentives. We are concerned this could discourage investment in BESS and lead to inefficient investment more generally. BESS and other technologies have been shown to improve security of supply and can provide flexibility services to the grid. So, it’s important the TPM doesn’t inadvertently discourage this investment, and risk leading to worse outcomes for consumer prices and reliability.

The Authority is proposing two amendments to the TPM to address these issues. The first amendment will ensure transmission connection charges for shared connection assets are allocated in a more proportionate way where a single customer both injects into and offtakes from the grid. The second amendment will change the way the residual charge is allocated for new customers and changes in consumption so that the effect on the residual charge of increased consumption is more consistent across customers. These changes will improve incentives for investment and allow different technologies, including BESS, to compete on a level playing field with other, more established technologies connecting to the grid. This in turn will ensure consumers keep benefiting in the long term through improved security of supply and relatively lower electricity prices.

Connection charges for shared connection assets

New Zealand’s first grid-scale Battery Energy Storage System is expected to be connected to the grid later this year, with others planned soon after. This process has revealed a potential issue with the way transmission connection charges are allocated for shared connection assets, which will lead to less than optimum outcomes for consumers.

For new connections, the TPM provides different rules for allocation of:

- initial charges during the first two years of connecting to the grid
- ongoing charges, after two years have passed since connection.

The issue we have identified relates to how ongoing charges for shared connection assets are allocated. These charges are currently based on the *sum* of a customer’s maximum demand and maximum injection. Under this rule, compared to similar-sized load customers or generators, technologies like BESS that both offtake and inject face substantially higher charges for shared connection assets – even though they don’t take up any more capacity.

The Authority is concerned the current Code requirements for connection charges could be discouraging efficient connection of BESS and hindering the flexibility of the wider system. BESS has the ability to become an important part of the system’s ability to respond efficiently to meet peak demand. Discouraging investment in technologies like BESS could impact security of supply and inefficient investment in network infrastructure. Ultimately, removing the discrimination against BESS will support security of supply and lead to lower electricity prices for consumers and less reliance on high-carbon-emission technologies.

The Authority intends to address this issue. This proposed amendment would ensure connection charges for shared connection assets are based on only the maximum capacity used for all customers. This approach will help to level the playing field for BESS and similar technologies compared to other customers. And it will help to improve security of supply and ensure that electricity prices for consumers are lower than they would otherwise be.

Residual charge annual adjustment

Several transmission customers have alerted us to a side effect of how the residual charge is adjusted when consumption changes (and when a new customer enters).[1] In short, the residual charge is currently calculated in such a way that a low load factor (peaky) customer who increases their energy consumption will experience a greater increase in their residual charge compared to a higher load factor (flat demand profile) customer who increases their consumption by the same amount.

The Authority is concerned this side effect of the way the residual charge formula operates may create a distortion where different customers face different costs from changing consumption patterns, investment in new load or investment in emerging technologies. This issue has become apparent due to the emerging investment in BESS as customers planning to install a BESS at the same location as a generation (which are typically low load-factor) are facing disproportionately higher costs. This issue risks slowing down the efficient adoption of new technologies, including BESS, and may discourage efficient connection of new load or lead to unnecessarily costly investment arrangements. If it is not addressed, this issue will lead to higher electricity prices for consumers.

We now want to amend the TPM to resolve this issue. We propose to change the way the residual charge is adjusted for changes in consumption and where new customers connect. Under the proposed amendment, changes in energy consumption (in MWh) would be converted to MW at the same rate for all customers.[2] New connections would be similarly charged, to avoid creating perverse incentives.[3] The proposed amendment would ensure changes in consumption have a consistent effect on charges for customers with different load profiles. It would correct the distorted incentives noted above and promote efficient investment, including in grid-scale BESS and other technologies. This will support a more efficient electrification of the economy and relatively lower electricity prices for consumers.

Estimated timing

Should the Authority decide to make these amendments, we propose they would come into force in April 2026, for pricing year 2026/27. This would allow sufficient time for Transpower

1 The residual charge is a transmission charge paid by load customers that is intended to recover revenue not recovered through other charges as efficiently as possible.

2 Our proposal applies to changes in energy consumption above the customer's baseline level of consumption. It does not change the approach for changes below the baseline level of consumption.

3 If new connections are not charged similarly, this could create perverse incentives to change business ownership arrangements in order to reduce residual charge allocation.

to make the necessary changes to its systems. This timeframe would not negatively impact customers currently making investments and connecting to the grid, as they:

- would be paying connection charges based on the rules for allocation of initial connection charges that apply in the first two years since connection. The identified issue with the connection charge does not arise for such initial charges.
- would not be paying the residual charge until after pricing year 2026/27, as load customers do not pay a residual charge for the first four years from connection.

Even though there is still some time before the changes will come into effect, we are addressing this issue now. This enables us to resolve these issues well in advance of when they would impact on transmission charges. Settling these issues now will also help to provide certainty for investment decisions being made now and in the coming years.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this paper is to consult with interested parties on the Authority's proposal to amend the transmission pricing methodology to:

(a) ensure connection charges for shared connection assets are allocated in a more proportionate way where a customer both injects into and offtakes from the grid

(b) change the way the residual charge adjusts where new customers connect or existing customers change their consumption so the adjustment is less affected by customers' load factors.

1.2. The TPM is a long and technically complex part of the Code. The Authority recognised that some issues may be identified during the TPM's implementation, requiring correcting amendments.

1.3. Clause 12.94A of the Code states the Authority may amend the TPM where it is satisfied on reasonable grounds regarding any of the matters in section 39(3) (e.g. technical and non-controversial amendments) or 40 (ie, urgent amendments) of the Act.

1.4. On 6 June 2024, the Authority released a decision to change the current drafting of clause 12.94A(2) to clarify it is also able to amend the TPM in circumstances not currently covered by clause 12.94A. In doing so it must include an explanation of whether it considers the amendment to be consistent with the intent of the most recent TPM guidelines published under clause 12.83(b) of the Code

1.5. The Authority considers that the first change, in respect of connection charges, is consistent with the 2020 TPM Guidelines. The Authority further considers that, while its change in respect of residual charge adjustments differs in its detail from the particular requirements of the Guidelines, it is nevertheless consistent with them by virtue of clause 2 as it ensures that the TPM better meets the intent of the Guidelines and the Authority's statutory objective. [4]

How to make a submission

1.6. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix E (word version attached alongside this paper). Submissions in electronic form should be emailed to network.pricing@ea.govt.nz with "Consultation Paper—" in the subject line.

1.7. If you cannot send your submission electronically, please contact the Authority at network.pricing@ea.govt.nz or on 04 460 8860 to discuss alternative arrangements.

1.8. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

[4] Refer to: 26850TPM-2020-guidelines-10-June-2020.pdf (ea.govt.nz)

(i) explain why you consider we should not publish that part, and

(b) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.9. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.10. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.11. Please deliver your submission by 5pm on Monday 16 September 2024.

1.12. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority network.pricing@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Connection charges for shared connection assets

2.1. This chapter describes an inconsistency that has been identified in the way that the TPM initially allocates transmission charges for shared connection assets, which results in BESS (and any other customers both injecting into and offtaking from the grid at different times) paying disproportionately high charges. We set out a proposed amendment that will ensure such charges are allocated in a more proportionate way, promoting a level playing field for investment in BESS.

Overview of connection charges

2.2. When determining the new TPM Guidelines in 2020, the Authority considered connection charges should be largely unchanged: the 2020 TPM Guidelines principally retained the 2006 Guidelines on connection charges, as they were considered largely consistent with efficient charging. The TPM 2020 Guidelines intent section states in respect of connection charges:

The purpose of the connection charge is to charge each designated transmission customer to recover the cost of the connection investments that connect that designated transmission customer's assets to the interconnected grid.

2.3. Connection assets are grid assets that exist specifically to connect a customer to the grid.[5]

2.4. The costs of a connection asset, where these are not covered by investment agreements, are recovered from the customers connected to it through connection charges.[6] If there are multiple connected customers, the costs and charges are shared between them, and the connection asset is referred to as a shared connection asset.

2.5. The asset, maintenance and operating components of connection charges are all calculated on a 'pool and share' basis. The asset, maintenance and operating components for a shared connection asset are shared between the customers connected to the asset according to their connection customer allocations (clause 32).

2.6. A customer's allocation for a connection location is the sum of the customer's anytime maximum demand and injection (AMDIC) at the connection location as a proportion of all customers' AMDIC at all connection locations the asset connects to.[7]

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5 Connection assets are grid assets even if the customer's assets are not directly physically connected to those assets. Connection (and interconnection) assets are defined in the TPM based on the physical configuration of the grid. The key distinguishing feature of connection assets is that they are configured so that there are no 'loop flow' effects on the assets, making it possible to identify the specific customer(s) without whom the assets would not exist. These customers are referred to as customers connected to the assets, even though they may not be connected directly.

6 An investment agreement is an agreement between Transpower and another person for Transpower to make an investment in the grid.

7 A customer's anytime maximum demand (AMDC) for a connection location and pricing year is the average of the 12 highest grid offtake quantities (MWh per half hour) for the customer at the connection location during the previous capacity year (1 September to 31 August), multiplied by two to convert to average demand (MW). Similarly for anytime maximum injection (AMIC), but for grid injection instead of offtake.

2.7. During the first and second pricing year after a customer connects (the 'initial period'), Transpower must set connection charges based on its estimates of either anytime maximum demand (AMDC) or anytime maximum injection (AMIC).[8]

2.8. How connection charges work is further explained in Transpower's connection charge information sheet.[9]

An inconsistency was identified with charges for shared connection assets

2.9. A potential issue with the connection charge adjustment clause was identified when considering the integration of a battery energy storage systems (BESS) into the grid at an existing connection location.

2.10. The integration of a large-scale connection (≥10MW) triggers a connection charge adjustment under the TPM. For connection charge adjustments, Transpower must determine whether the connecting customer will serve as an offtake or injection customer and estimate the customer's anytime maximum demand for consumption (AMDC) or anytime maximum injection capacity (AMIC), depending on Transpower's determination.

2.11. During the initial two-year period, Transpower must estimate the connection charge allocation at a shared connection asset using either AMDC or AMIC.

2.12. After this period, the customer allocation is calculated by combining the customer's anytime maximum demand and injection (AMDIC).

2.13. Most transmission customers will primarily be either load or injection, which means their connection charges will remain largely unchanged after the initial period.

2.14. For technologies like BESS, the connection charge allocation during the initial period will be similar to that of an equivalent-sized load customer or generator. However, after this period, the BESS or a similar technology could be charged double the connection charge of an equivalent-sized load customer or generator. This is because they both inject into and offtake from the grid, with their allocation at the shared connection asset being based on both their anytime maximum demand and injection (AMDIC).

2.15. Connection charges at shared points of connection risk disproportionately impacting BESS, creating an artificial commercial disadvantage. This may discourage investment in BESS, leading to an inefficient mix of energy generation sources. This could in turn result in higher electricity prices and exacerbate security of supply problems in meeting peak demand – noting the importance of BESS solutions to meet winter coordination challenges.[10] The Authority seeks to ensure a level

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8 A customer may have an allocation for the same connection asset at more than one connection location. If a customer notifies Transpower in writing that its grid-connected assets have been physically altered so the capacity of the assets has been permanently reduced, and Transpower is reasonably satisfied this has occurred, it will estimate the customer's AMDIC for the reduced capacity, which will reduce the customer's allocation for shared connection assets (clause 33). This also applies if plant connected to the customer's assets has undergone a large derating (capacity reduced by at least 10MW).

9 Refer to: TPM Information sheet - Connection Charges - v2.pdf (transpower.co.nz)

10 For more information on how BESS can assist with security of supply issues, refer to the Authority's consultation paper: Potential solutions for peak electricity capacity issues

playing field, so technologies like BESS are not artificially advantaged or disadvantaged.

Proposed amendment for connection charges

2.16. The Authority is proposing a change to clause 32 of the TPM to calculate the allocation for connection charges for shared connection assets based on the greater of either demand (AMDC) or injection (AMIC) for each customer.

2.17. When considering connection charges in the TPM, the Authority considers these charges should be based on the capacity used. In other words, connection charges should be determined by the maximum capacity that a transmission customer needs to either inject into or offtake from the grid.

2.18. The grid connection infrastructure, including transformers, switchgear, and transmission lines, is sized according to the maximum expected power flow. The physical and electrical limits of these components are determined by their rated capacity, which ensures safe and reliable operation under peak load conditions.

2.19. For technologies such as a 100MW BESS, the system has capability to either inject up to 100MW of power into the grid or offtake up to 100MW of power from the grid. However, for technological reasons BESS cannot perform both injection and offtake simultaneously. It can either be in a state of charging (offtaking power from the grid) or discharging (injecting power into the grid) at any given moment, but not both.

2.20. The proposed amendment ensures the charges are capacity-based, reflecting the actual demands placed on the grid connection infrastructure. The status quo in relation to technologies such as BESS is not based on capacity. We consider that capacity is the appropriate allocation basis for connection charges.

2.21. We consider the greater of demand and injection is the appropriate allocation basis for shared assets. The proposed amendment better meets the Authority's main statutory objective. It does this through putting technologies such as BESS on a level playing field in terms of competition as compared to other generators and ensures the TPM does not inefficiently discourage investment in BESS. This mitigates potential downstream consequences such as inefficient investment, higher consumer prices and security of supply problems in meeting peak demand.

2.22. Under the proposed amendment, where a new BESS connects to a shared connection asset, the other customers at that shared connection will still pay lower connection charges, as the cost will be shared. However, the proposed amendment will put BESS and other customers on a level playing field, so those customers would pay a greater share than they would have under the current TPM. For customers with existing shared connection assets, the proposed change would create some rebalancing of connection charges – we consider this further below.

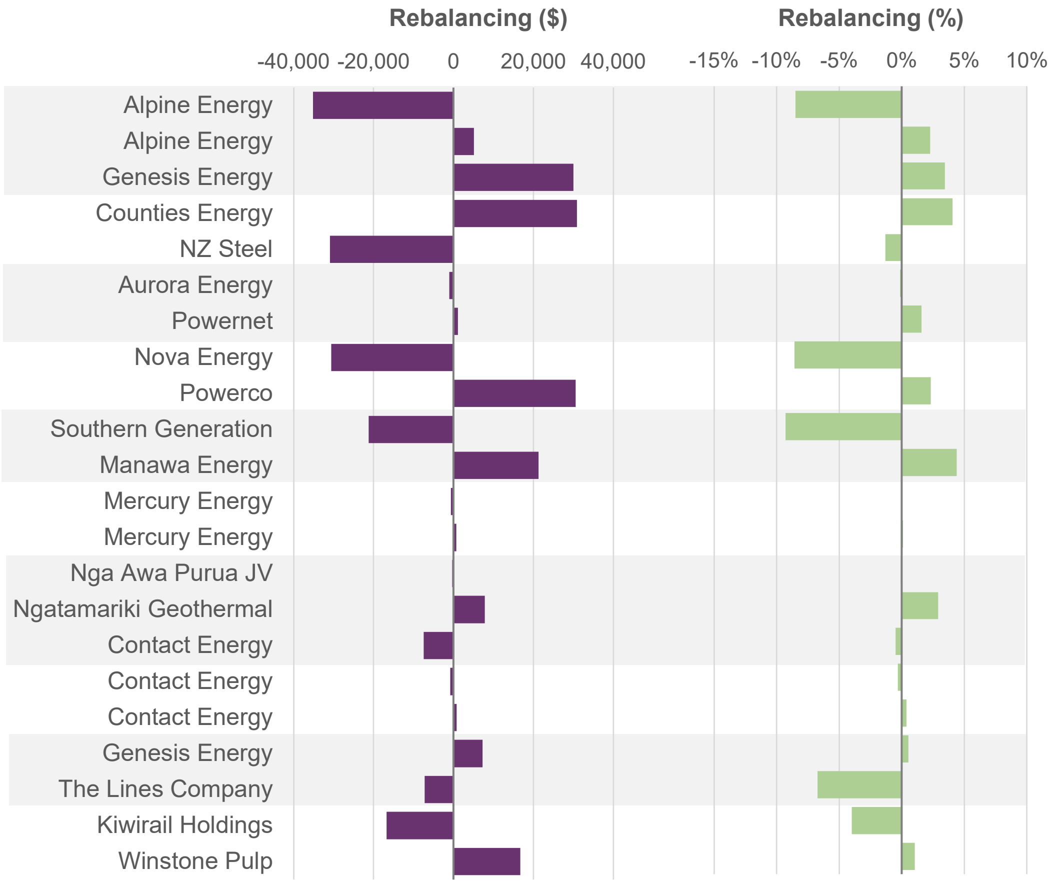
2.23. The Authority proposes the change would only apply from April 2026 to ensure Transpower would have sufficient time to make necessary changes and engage with its customers. In our view, informed by Transpower's operational feedback, a change for pricing year 2025/26 is unlikely to be possible.

Illustration of impact on connection charges

2.24. We asked Transpower to assess the indicative impact on connection charges on current customers from this proposed change relative to the status quo. Currently there are 24 locations with shared connection assets, of which 15 are impacted by the proposal.

2.25. Figure 1 below shows where the proposed change would be expected to lead to a rebalancing of connection charges, based on the PY2023/2024 connection charges (as notified by Transpower in December 2023), for customers at shared connection locations. We have excluded connection locations where no impact is estimated. Connection charges would increase by up to $30,892 (a 9% increase) and reduce by up to $35,124 (a 9% decrease).

Figure 1: Estimated customer impact of proposed amendment (based on PY 2023/24)



Source: Electricity Authority modelling based on Transpower data

Q1. Do you agree with the proposed amendment for connection charges for shared connection assets?

Q2. Will the proposed amendment have any unintended consequences for unusual connection arrangements, eg complex connections?

3. Residual charge

3.1. This section sets out an issue with the allocation of the residual charge, which results in some customers (including investors in BESS) paying disproportionately high charges where they connect new plant or otherwise change their consumption. We outline a proposed amendment to the way the residual charge is allocated in respect of increases in consumption for existing customers and the estimation of initial allocations for new customers so the effect on the residual charge of increased consumption is more consistent across customers. These changes would improve incentives for investment and promote a level playing field, particularly for investment in BESS.

Overview of residual charge

3.2. The residual charge is intended to recover revenue not recovered through other charges as efficiently as possible. The residual charge is not intended to actively influence grid use or investment. By contrast, other prices have a signalling role: connection charges and benefit-based charges, along with nodal pricing in the spot electricity market, are intended to provide price signals for efficient grid use and efficient investment decisions and thus operate for the long-term benefit of consumers by reducing costs.

3.3. The revenue recovered from load customers via the residual charge is high initially but will reduce over time as the value of historical grid investments in Transpower's asset base reduces with depreciation.[11]

3.4. Residual charges are, initially, paid by load customers in proportion to their anytime maximum gross demand (AMDR),[12] measured in MW. This is based on the load customer's maximum gross consumption at each of its points of connection to the grid but is non-coincident across the customer's points of connection (ie, a customer's maximum gross demand at one point of connection can occur at a different time to their maximum gross demand at a different point of connection).

3.5. For the first four years after they connect, a load customer does not pay a residual charge (the customer's allocator (AMDR) is fixed at zero). For the subsequent four years, its AMDR increases in 25% increments up to its AMDR baseline.

3.6. The baseline AMDR is set:

(a) based on the historical anytime maximum demand (AMD) for existing load customers

(b) by estimating the AMD for new load customers.

3.7. For all subsequent years, the baseline AMDR is adjusted each pricing year based on the customer's lagged change in gross energy consumption. This adjustment is

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11 Revenue recovered through the residual charge will not increase due to new investments in the interconnected grid or upgrading expenditure. These costs are recovered via the benefit-based charge.

12 This measure finds the single trading period where the customer's energy consumption (in MWh) is highest and multiplies this energy consumption by two to get the average demand (in MW) during that half-hour.

made using a residual charge adjustment factor (RCAF), which is calculated based on the ratio of:

(a) the customer's lagged average total gross energy (LATGE); [13] to

(b) the customer's baseline average total gross energy (ATGE).[14]

3.8. More information about how the residual charge is allocated can be found in Transpower's residual charge information sheet.[15]

Key design choices for the residual charge

3.9. The Authority's intended purpose for the residual charge was that it should be "designed to minimise any effect on designated transmission customers' decision-making". The Authority also recognised that residual charges should be in proportion to the "size" of the customer and that changes over time in the relative size of customers should be reflected through updates to residual charge allocation.

3.10. To achieve these goals, the Authority decided that "it would be consistent with the long-term benefit of consumers for the initial allocation of the residual charge to be based on historical gross AMD" and "adjusted annually based on changes in the four-year rolling average of gross annual energy usage, with a lag".[16][17]

3.11. The Authority considered using energy consumption (MWh) for the initial allocation, but preferred capacity (AMD). The Authority considered capacity to be a suitable proxy for size and ability to pay, and that it was preferable to energy consumption, which was "judged likely to have a material adverse impact on some industrial load customers, which could potentially lead to inefficient disconnection".[18] An allocator based on AMD would be less likely (than a MWh allocator) to cause the disconnection of a large industrial consumer (as such consumers tend to have relatively flat load profiles)."[19] As such, the Authority selected a historical measure of AMD as the allocator for the initial residual charge.

3.12. The Authority considered updating the residual charge allocation based on changes to a customer's AMD. However, updating a customer's allocation based on their change in gross AMD could be distortionary, even with a lag, as "AMD is a measure of peak demand that a customer could adjust at low cost relative to other measures (such as total usage). AMD is also easier for a customer to predict and control".[20]

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13 This is the average total gross energy over the period of four financial years, commencing eight financial years ago – eg. for pricing year 2023/24, the relevant lagged period is from financial year 2015/16 to financial year 2018/19. As such, a change in energy consumption will only affect the RCAF after four years.

14 For existing customers, this is based on their historical total gross energy, whereas for new customers it is estimated.

15 Refer to: TPM Information sheet on residual charges v3.pdf (transpower.co.nz).

16 10.25 and 10.50, 2020 guidelines decision paper - Long-form report (ea.govt.nz)

17 The lag period means that 2018–19 energy usage enters the rolling average — and the updates will begin to be made — in the 2023–24 pricing year. The lag period was chosen as the Authority considered that the period strikes the balance between the speed at which charges align to changes in customers' ability to pay and the increase in inefficient incentives to reduce consumption. 2020 guidelines decision paper- Long-form report (ea.govt.nz)

18 5.4, 2020 supplementary consultation on 2019 issues paper - Long-form report (ea.govt.nz).

19 B.204, 2019 issues paper - Long-form report (ea.govt.nz).

20 5.10, 2020 supplementary consultation on 2019 issues paper - Long-form report (ea.govt.nz).

3.13. The Authority also considered using annual ICP count to update the residual charge allocation. However, it considered this would not be suitable for direct-connect industrials, so a mixed approach would be required. This could "create a risk of commercial consumers re-arranging their affairs (for example, embedding) to minimise their charges".

Issue identified with the residual charge annual adjustments

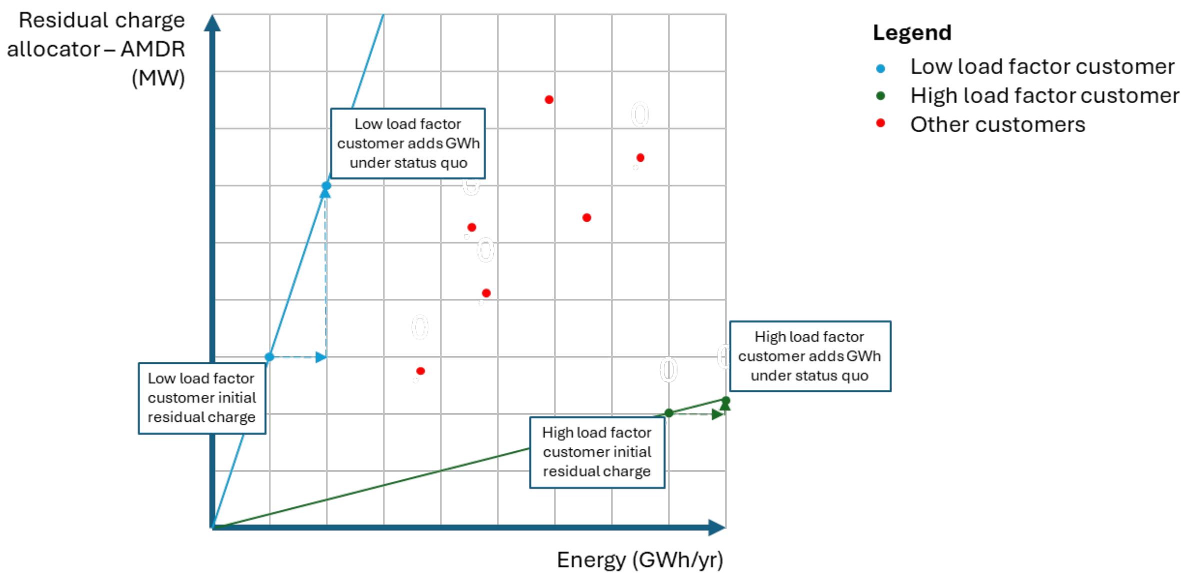
3.14. In this section we explain the residual charge issue and the potential outcomes if we do not address the issue.

Problem definition

3.15. Under the current TPM, the incremental cost of increased energy consumption (in $/MWh) under the residual charge will vary based on the relationship between a customer's baseline capacity and baseline gross energy consumption. This ratio is also commonly known as a customer's 'load factor'.

3.16. A customer's load factor represents the ratio of its actual electricity consumption over a certain time to the theoretical baseload consumption over the same time at nameplate capacity (as shown by the slopes of the lines in Figure 2). A 'peaky' customer with a low load factor, such as a distributor that supplies a lot of holiday homes or a generator with a small amount of peaky load at the same point of connection to the grid, only uses a small percentage of its installed capacity on average. This may be because it consumes its maximum load infrequently, consumes only a small proportion of its maximum load, or a combination of the two. On the other hand, a 'flat' customer with a high load factor, such as a major industrial user, will use a high proportion of its capacity on average.

Figure 2: Status quo



3.17. For the purposes of residual charge allocation, increases in consumption for peaky customers (with low baseline load factors) are effectively converted to MW at a higher rate compared to flat demand customers (with high baseline load factors). This means a low load factor customer that increases its energy consumption will experience a larger increase in its residual charge allocation than a high load factor customer that increases its energy consumption by the same amount.

3.18. Furthermore, a new customer's residual charge depends on the AMD of the new load it is connecting, whereas if the same new load is added by an existing customer, its increase in residual charge will also depend on the load factor of its (pre-existing) baseline load.

3.19. Essentially, the incremental residual charge (in $/MWh) for additional energy consumption will vary depending on the type of customer that increases consumption.

3.20. This issue was not raised in submissions in response to the Authority's 2019 proposal on the TPM guidelines. Another issue relating to allocation of the residual charge to BESS was specifically consulted on in 2021,[21] but the conversion factor issue considered in this paper was not specifically addressed. However, Trustpower raised the conversion factor issue in its 2021 submission on the proposed TPM.[22] Detailed evidence of the issue was not available at the time, and the Authority was not convinced that the issue was material.

3.21. Since 2021, there has been a significant increase in proposed investment in BESS. While the conversion factor issue is not specific to BESS, it does appear to be particularly severe for generators with a low load factor (perhaps due to peaky load co-located at the same point of grid connection) that are looking to invest in load, such as a BESS co-located with the generation. This was not a scenario that was considered in 2021 in the context of residual charge allocation.

3.22. The Authority has now had the benefit of estimated residual charges have been modelled for two new proposed BESS investments and brought to our attention. Based on this new evidence, we have formed the view that the issue does create a material distortion. Having considered detailed modelling of the issue, prompted by investment in new technology (BESS), the Authority now considers that the issue creates a material distortion and considers that it should be addressed.

Worked example

3.23. For example, assume Customer A has a baseline AMD (capacity) of 150MW, but has a relatively high load factor and therefore an energy consumption baseline of 1,000GWh per year. Customer B is a low load factor customer, so while it has a higher baseline AMD (capacity) of 600 MW, it has the same energy consumption baseline as Customer A. Because the initial residual charges are allocated based on capacity, Customer B will have an initial residual charge that is four times that of Customer A.

3.24. Now consider what happens when both customers increase consumption by 1,000GWh per year – through new load or greater utilisation of their capacity.[23] That increase in consumption will be converted to MW at a rate that is four times higher for Customer B (peaky) than for Customer A (flat demand). So the

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21 The issue considered in the 2021 proposal related to capturing only battery losses in terms of offtake for residual charge allocation purposes.

22 Trustpower-TPM-submission-2021.pdf (ea.govt.nz)

23 Eg, doubling their energy consumption and giving them a residual charge adjustment factor of 2.

incremental residual charge from the new load will cost Customer B four times what it will cost Customer A, even though both customers have increased their consumption by the same amount. We set out the figures from this example scenario in Table 1 below.

Table 1: Residual charge issue worked example

	Customer A	Customer B
Baseline capacity ($AMDR_{baseline}$)	150MW	600MW
Baseline energy consumption ($ATGE_{baseline}$)	1,000GWh/yr	1,000GWh/yr
Load factor	High (76%)	Low (19%)
Residual charge in baseline year (based on $AMDR_{baseline}$)	$10m	$40m
Increase in energy consumption	1,000GWh/yr	1,000GWh/yr
Lagged average consumption ($LATGE_n$)[24]	2,000GWh/yr	2,000GWh/yr
Residual charge adjustment factor ($RCAF = LATGE_n / ATGE_{baseline}$)	2	2
Residual charge allocator ($AMDR_{baseline} \times RCAF$)	300MW	1,200MW
Residual charge in year n (based on updated $AMDR_n$)	$20m	$80m
Increase in residual charge	$10m	$40m
Incremental cost of additional energy consumption	$10/MWh	$40/MWh

Potential outcomes if we do not address the issue

3.25. Having different incremental residual charge rates for increased consumption depending on the customer's load factor could result in several perverse incentives. Firstly, it could discourage existing transmission customers with low load factors from productive increases in their energy consumption, such as a low load factor industrial customer growing its output by investing in new factory equipment or increasing utilisation of existing facilities. Industrial customers with a higher load factor baseline would face less of an increase in the residual charge for the same increase in energy consumption and, all else being equal, would be more likely to determine such expansion to be viable.

3.26. Secondly, it could result in new load (such as a new BESS) being located based on where it will have lower incremental residual charges. This may be in a location that is inefficient from a network congestion or wholesale market perspective.

(a) Existing transmission customers with low load factors that are looking to add new load will be incentivised to co-locate the new load with another customer that has a higher load factor. For example, a generator looking to add a new BESS may seek to embed it within a distribution network or co-locate it with a

24 Where n = four years after the increase in energy consumption.

major industrial user.[25] All else being equal, this would make it less likely the BESS is co-located with the generation,[26] which could be an inefficient result for the system as a whole.[27] .

(b) New transmission customers will be incentivised to co-locate the new load with an existing customer whose load factor is higher than the load factor Transpower would assume for the new customer when setting its baseline AMDR and baseline ATGE. For example, for a new BESS, Transpower may set a high baseline AMDR relative to its baseline ATGE, giving it a low load factor. This could, for example, incentivise the developer to instead connect it to a distribution network where it will have a lower residual charge (assuming the distributor passes through the incremental residual charge without any cross-subsidisation).

3.27. Thirdly, it could result in new customers sequencing their developments in inefficient ways. New customers looking to connect to the grid will be incentivised to connect load with a higher load factor first (to set a high baseline ATGE relative to its baseline AMDR) and add additional loads with lower load factors in later years (to have a lower effect on the RCAF).

3.28. Fourthly, existing transmission customers with low load factors seeking to add higher load factor load could be incentivised to connect such load to the grid through a commercial entity that is a new transmission customer. The new customer will have a residual charge based on its baseline AMDR, which will be relatively low compared to its ATGE (which would have driven its incremental residual charge if the load had been added under an existing customer).

3.29. Such outcomes would create an uneven playing field for transmission customers. Some customers, depending on their load factor and whether they are an existing transmission customer, would be able to alter their consumption or add new load and face different changes to their residual charge as a result. This may incentivise some activities that are not efficient, disincentivise other activities that are efficient, and reduce competition as some transmission customers may be at a disadvantage to others.

3.30. Such outcomes, if they were to arise, would not better meet (when compared to options that avoid such outcomes):

(a) the intent of the TPM Guidelines, which require a residual charge that is "designed to minimise any effect on designated transmission customers' decision-making"

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25 The generator may have some peaky load connected at the same point of connection to the grid. This could result in the generator paying a residual charge – and could mean the load factor is low.

26 Co-locating BESS with a solar farm could allow the solar farm to shift its injection of electricity to peak times when it is more valuable.

27 For example, it could be an inefficient result for the system as a whole if it results in greater transmission losses or DC:AC conversion losses.

(b) the Authority's main statutory objective to promote competition in, and the efficient operation of the electricity industry for the long-term benefit of consumers.[28]

3.31. Over time, this decrease in efficiency and competition could flow through to higher prices for consumers. The uneven playing field described in 3.29 may slow down the efficient adoption of new technologies, and with respect to BESS technology, it may favour investment by certain existing transmission customers over other transmission customers and new entrants. This could reduce competition in the wholesale market, resulting in higher prices and lower reliability than would otherwise have been the case. The uneven playing field may also extend to inefficient behaviour and uneven competition involving activities that depend on electricity supply. For example, high load factor industries and/or high load factor businesses within an industry may find it easier to proceed with investments that result in new load and/or increased consumption over low load factor participants. This may discourage efficient connection of new load or lead to unnecessarily costly connection arrangements as customers seek to minimise their share of charges.

Proposed amendment for residual charge annual adjustments

3.32. To address the issue with residual charge allocation discussed above, we propose to amend the Code to change the way the residual charge is allocated in respect of new connections and changes in consumption so the effect of incremental consumption on the allocation is more consistent across customers. This is a significant change to the way in which the residual charge works, which in our view will materially improve efficiency. Our proposal has two components.

3.33. First, we propose that for changes in energy consumption above the customer's baseline level of consumption ($ATGE_{baseline}$), such changes would be converted to MW at a uniform rate for residual allocation purposes. This would mean all existing customers pay the same incremental increase in residual charge for a given amount of additional gross energy consumption.

3.34. Our proposal does not change the approach where a customer decreases its energy consumption below its baseline level of consumption ($ATGE_{baseline}$). So long as a customer's consumption is below its baseline level, changes in consumption would continue to be converted to MW in the way set out by the existing TPM, ie, based on the customer's individual load factor.

3.35. Second, we propose to change how the initial residual charge for a new customer is set. Under our proposal, a new customer's initial residual charge will no longer be based on its own estimated capacity. Instead, it will be determined based on its estimated energy consumption and converted to MW using the average load factor of existing customers.

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28 The Authority's work on transmission pricing is being progressed under its main objective: to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Residual charge allocator and conversion factor

3.36. Our proposal to convert changes in energy consumption to MW at a uniform rate for residual allocation purposes is achieved by changing the way each load customer's "residual charge allocator" is calculated.

3.37. A customer's residual charge allocator is a number, in MW, which is used to derive the share of total residual charges paid by the customer in a given year.[29] In the current TPM, a customer's residual charge allocator in a given year can be represented as the sum of two parts:

(a) initial allocation = the customer's baseline AMD (AMDR baseline), in MW

(b) annual adjustment = changes in the customer's energy use in MWh (lagged), converted to MW, to provide a consistent basis for residual charge allocation.

3.38. The annual adjustment component of the residual charge allocator can be calculated by multiplying the lagged change in energy by a 'conversion factor'. This conversion factor is the customer's baseline capacity (AMD) divided by the customer's baseline energy consumption ($AMDR_{baseline}$ / $ATGE_{baseline}$).[30] It effectively converts the customer's lagged change in energy (a MWh figure) into a figure that can be added to or subtracted from the customer's capacity baseline (a MW figure).

3.39. The allocation issue discussed in this section arises because every customer's conversion factor is different – as the conversion factor is calculated individually using each customer's own baseline capacity and baseline energy consumption. A customer will have a conversion factor that is effectively the inverse of its load factor, so 'peaky' customers will have a low load factor and a high conversion factor and 'flat' customers will have a high load factor and a lower conversion factor. This results in the same change in energy use being converted to different sized changes in AMDR and therefore the residual charge allocation.

Uniform conversion factor for changes in consumption above baseline levels

3.40. To address the issue with the residual charge annual adjustment mechanism, our proposed solution is to amend the Code so that a uniform conversion factor is used for all customers, for changes in energy consumption above baseline consumption. This means all customers would pay the same incremental increase in residual charge for a given amount of additional energy consumption.

3.41. The new uniform conversion factor would be based on the sum of baseline capacity and the sum of energy consumption across all customers. Essentially, it is the weighted average conversion factor of all customers, as shown by the slope of the red line in Figure 3 below. Customers would continue to have different capacity baselines and different changes in energy consumption. However, a single number

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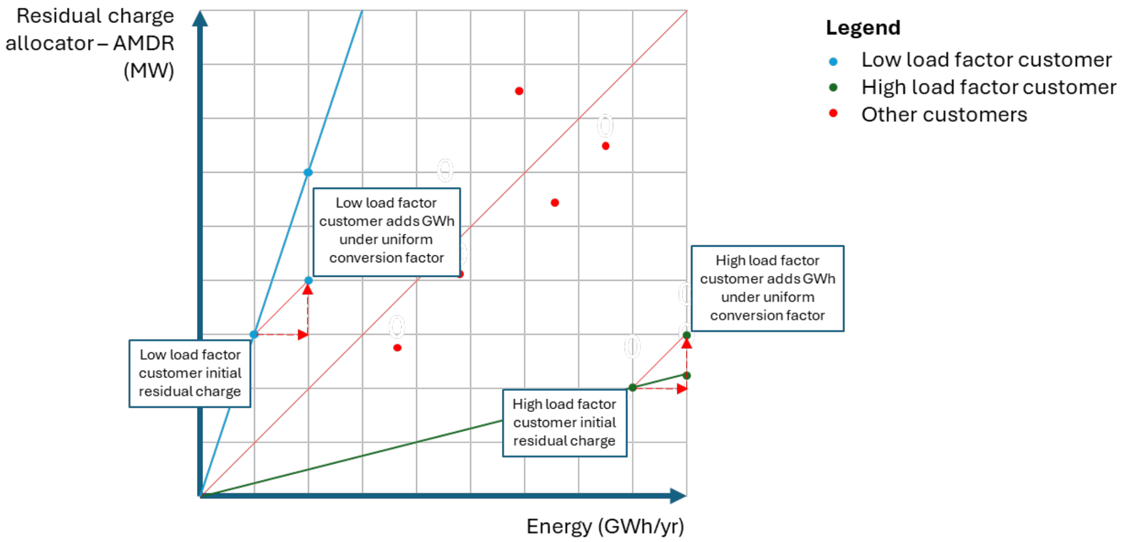
29 The residual charge is allocated between load customers in proportion to each customer's residual charge allocator. The share of total residual charges is given by the customer's residual charge allocator for the given year divided by the total of all load customers' residual charge allocators for that year.

30 To assist explanation of the issue and the proposed solution, in this chapter we discuss residual charge allocation in a way that is different from the way this topic is represented in the TPM. For example, the words "conversion factor" do not currently appear in the TPM. For those who wish to understand how the discussion presented here relates to the formulas in the TPM, please refer to Appendix C.

in the form of a uniform conversion factor would be used to calculate their residual charges.

3.42. This means the same change in energy consumption would be converted into the same-sized change in MW (AMDR) and therefore the same change in residual charge, as shown in Figure 3.

Figure 3: Uniform conversion factor for changes in consumption above baseline



3.43. To continue our example from Table 1, a uniform conversion factor would result in Customer A and Customer B both paying an additional $25m in residual charges for their additional 1,000GWh of load per year, equating to an incremental charge of $25/MWh for the new load.

3.44. This means all customers would face the same residual charge costs for the same actions. As such:

(a) decisions about increasing consumption or adding new load would not be inefficiently based on minimising residual charges under the TPM

(b) all transmission customers would be competing on a level playing field, regardless of their load factors.

3.45. These outcomes, which will be achieved by the proposed amendment, are consistent with the Authority's main statutory objective and the intent of the TPM Guidelines (see paragraph 3.30 above). The proposed amendment would ensure a uniform incremental residual charge rate for increased consumption, regardless of the customer's load factor. By doing so, it would address the perverse incentives noted at para 3.25– 3.31 above, and so promote competition and efficient investment, ultimately resulting in relatively lower prices for consumers.

3.46. While the incremental change is constant across customers, we note the average residual charge on a dollars per megawatt hour basis will not be the same for every customer. For example, Customer A's total residual charge would still be lower than Customer B's ($35m compared to $65m), despite their total energy consumption being the same. This is because the initial allocation of the residual charge was set using a baseline AMDR measurement, rather than an energy measurement.[31] It is not proposed to change the initial allocation of the residual charge for existing customers. This proposed change is focused on ensuring an even playing field going forward for customers adding new load or increasing energy consumption.

3.47. While the example above refers to increases in consumption, under our proposal the uniform conversion factor also applies to decreases in consumption.[32] This would mean that a reduction in a customer's energy consumption would result in a consistent reduction to its AMDR. The benefits of this approach are that reductions to energy consumption would be treated consistently between customers regardless of load factor, with similar benefits to the broader proposal to introduce a uniform conversion factor. This would create an even playing field for:

(a) providers of long-term demand response – they will have equal residual charge incentives to do so regardless of customer type (ie, a low load factor customer and a high load factor customer will receive the same lagged decrease in their residual charge for providing the same amount of demand response in energy terms).

(b) customers with both grid-connected and embedded loads that are looking to reduce energy consumption – they will have equal residual charge incentives to do so at either of these locations.

(c) customers looking to increase embedded generation (in such a way that it may not be counted towards their gross energy due to measurement limitations) – they will have equal incentives to do so regardless of customer type. For example, a lower load factor distributor and a higher load factor distributor will have the same incentives to promote small-scale rooftop solar.

3.48. However, as discussed in the next section, under our proposal the uniform conversion factor does not apply where the customer's lagged consumption falls below the customer's baseline consumption level.

Unchanged approach for changes in consumption below baseline levels

3.49. Our proposal does not change the approach to residual charge allocation for changes in energy consumption below baseline consumption levels. The new uniform conversion factor would not apply for such changes; ie customers' individual conversion factors would continue to apply as per the current TPM.

3.50. We note that for most customers, the below-baseline scenario appears less likely to arise, as lagged consumption is likely to exceed baseline consumption for the foreseeable future, due to the ongoing electrification of the economy. Nevertheless, some customers may fall below baseline, due to energy efficiency or industrial exit.

3.51. If a transmission customer reduces lagged energy consumption below baseline consumption levels, a uniform conversion factor could result in a new AMDR that is counterintuitive. This is because the reduction in the customer's energy consumption would reduce its baseline AMDR (which is based on the customer's

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31 See paragraphs 3.2 through 3.9 above.

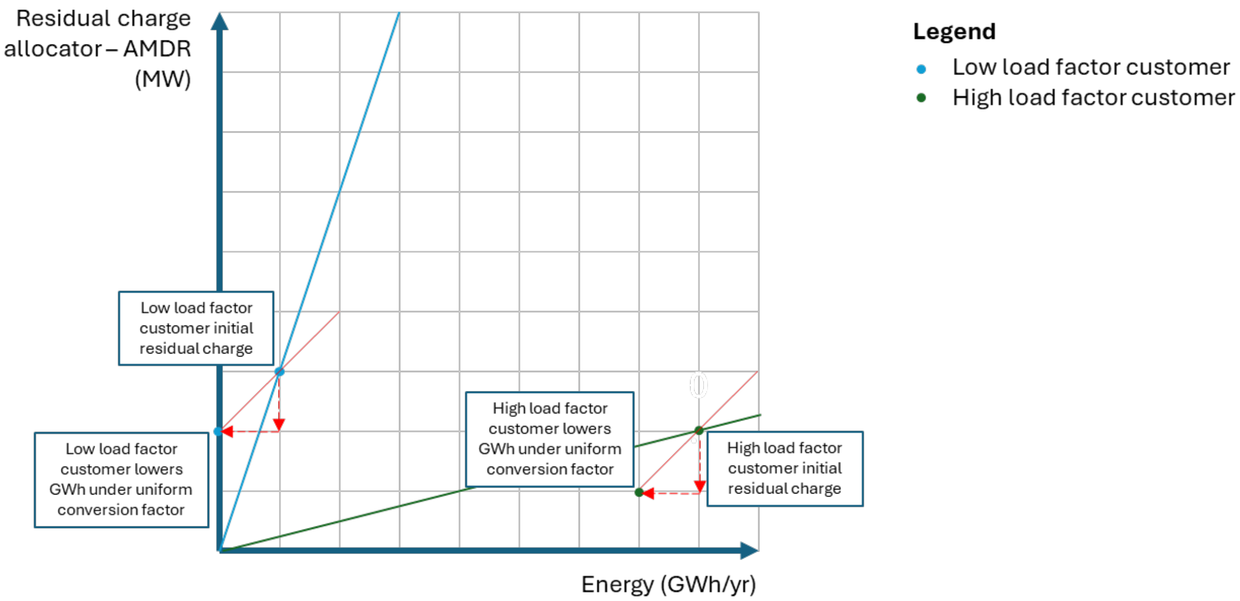
32 Provided the customer's lagged consumption level remains above the customer's baseline consumption level.

capacity) by an amount that ignores the customer's load factor (and by extension, ignores the customer's capacity). This can lead to a residual charge allocation that does not reflect a customer's size, as outlined in Figure 44 below.

3.52. Low load factor (peaky) customers could be left with a substantial proportion of their residual charge even after reducing their load by a significant amount, or, in theory, even after reducing it entirely.

3.53. High load factor (flat) customers could reduce their residual charge by a substantial proportion – in theory, even to or beyond zero – after reducing their load by a proportionately smaller amount.

Figure 4: Uniform conversion factor for changes in consumption below baseline



3.54. We have considered the following options for changes in energy consumption below baseline levels:

(a) Option 1: Uniform conversion factor applies only where the customer's lagged consumption is above the customer's baseline consumption level (LATGE > $ATGE_{baseline}$)

(b) Option 2: Uniform conversion factor applies for all changes to energy consumption

(c) Option 3: Uniform conversion factor applies for all changes to energy consumption, but Transpower has ability to re-estimate customers' AMDR.

3.55. Our proposal adopts option 1. We recognise that there is no perfect approach to allocating the residual charge. However, on balance, the potential for the uniform conversion factor to reduce a customer's residual charge in a materially disproportionate way when the customer reduces its energy consumption below its baseline level leads us to prefer option 1.

3.56. Under our proposal, in situations where a customer's lagged consumption (LATGE) is lower than its baseline consumption level ($ATGE_{baseline}$), a customer's AMDR is adjusted as per the status quo (ie, using the customer's individual conversion factor, based on its own load factor). This approach avoids the unintended outcome (as discussed at para 3.50 to 3.53 above) where a customer that reduces its lagged energy consumption below its baseline consumption level (ATGE baseline) can end up with an AMDR and therefore residual charge that is materially disproportionate to its size. We considered whether the use of an asymmetric approach creates unintended consequences. It does mean that changes in consumption for a customer with above baseline consumption will have different residual charge implications than the same change for a customer with below baseline consumption. This could potentially have negative implications for competition, however we do not see these potential implications as material or likely to occur frequently.

3.57. Option 2 would apply a uniform conversion factor for all changes in consumption – including in situations where lagged consumption was below baseline levels ($LATGE < ATGE_{baseline}$). This would mean that changes in a customer's energy consumption would result in consistent changes to its AMDR, even where consumption was below baseline. Under option 2, the benefits noted above (see paragraphs 3.45 and 3.47 above) would apply in a broader range of situations, including where consumption was below baseline. Option 2 would also address the potential negative implications for competition noted in the preceding paragraph. However, this option does not address the problems discussed at paragraphs 3.50 to 3.53 above. On balance, our view is that these problems would likely outweigh the benefits of extending the uniform conversion factor to below-baseline situations – noting that:

(a) it is important for the durability of the TPM that residual charge allocation continues to reflect customers' relative size

(b) as noted above, the below-baseline scenario appears less likely to arise, as lagged consumption is likely to exceed baseline consumption for the foreseeable future.

3.58. Option 3 would require Transpower to reset a customer's AMDR where there is a significant decrease in AMDR below the baseline as a result of any substantial decrease in gross energy consumption or AMD that Transpower deems, in its discretion, will result in the customer being allocated a residual charge that does not affect its size or ability to pay. Whilst it would provide flexibility to address particular circumstances as they arise, we do not prefer this approach as giving Transpower this discretion could create uncertainty. Transpower has also indicated that it would prefer a process that minimises its discretion.

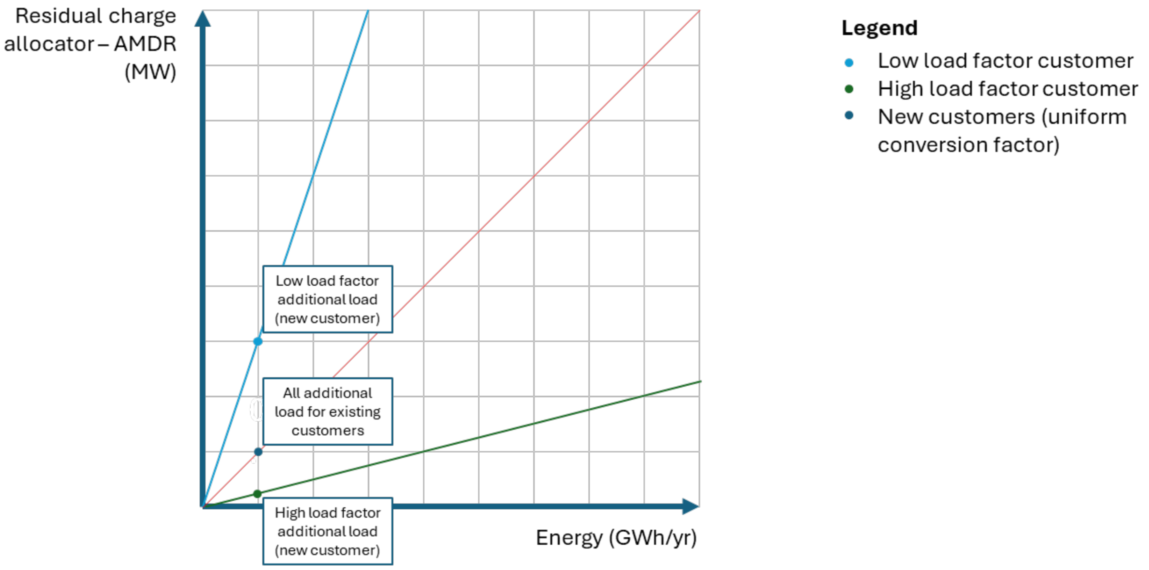
Uniform conversion factor for new transmission customers

3.59. The second part of our proposal with respect to residual charge allocation is a change to the way the initial residual charge for a new customer is determined. Under our proposal, a new customer's initial residual charge would no longer be based on its own estimated capacity. Instead, it would be determined based on its estimated energy consumption and converted to MW using the average load factor of existing customers. This is so that an increase in energy consumption would result in the same incremental change to the residual charge for all customers, regardless of whether it was for a new connection or an increase in consumption for an existing customer. This proposed change is a consequence of our proposal to adopt a uniform conversion factor for existing customer's increases in energy consumption.

3.60. Under the status quo, the initial residual charge for a new transmission customer is based on Transpower's estimate of its gross AMD. In terms of Figure 4 below, this means the residual charge for a new customer under the status quo reflects its estimated gross capacity (the light blue or green dots in Figure 1).

3.61. Also under the status quo, the residual charge increase for an existing customer is based on its individual load factor (the blue or green lines in Figure 4), so would result in the same equivalent increase to AMDR.

Figure 1: Uniform conversion factor: new customers compared with existing customers



3.62. However, under the proposal to use a uniform conversion factor for existing customers, the additional energy consumption by an existing transmission customer would result in residual charge increases commensurate with the uniform conversion factor (the red line in Figure 4).

3.63. If such a discrepancy between new and existing customers was created, it might provide scope for customers to reduce their residual charges (and shift them to other customers) by:

(a) existing transmission customers connecting new load through commercial entities that are not currently transmission customers when the new load is expected to have a higher load factor than the existing customer's load factor.

(b) new transmission customers co-locating their load with existing transmission customers when the new load is expected to have a lower load factor than the existing customer's load factor.

3.64. The perverse incentives created by such a discrepancy could lead businesses to engage in inefficient investment and adopt arrangements that are unnecessarily costly. ultimately resulting in relatively higher prices for consumers.

3.65. To mitigate incentives that may arise as result of the proposal to adopt a uniform conversion factor for energy consumption increases for existing customers, we have developed this second part of our proposal on residual charge allocation. We propose that Transpower should set a new customer's AMDR based on the customer's anticipated energy consumption converted into AMDR using the uniform conversion factor (based on the weighted average load factor of all existing customers). We consider that this approach better promotes the Authority's main statutory objective than the status quo where Transpower estimates a new customer's anticipated AMD directly, because it removes perverse incentives, leading to more efficient investment, and ultimately relatively lower prices for consumers.

3.66. However, we have also considered a potential disadvantage of this part of the proposal, which relates to competition between existing transmission customers and new entrants. Under our proposal new customers would have their entire residual charge based, in effect, on expected energy consumption, whereas existing customers would have their baseline AMDR set on capacity and only adjusted based on energy. Adopting a uniform conversion factor for existing customers' increases in energy consumption and the consequential change to also use the uniform conversion factor for new customers requires us to accept the following trade-off:

(a) address a discrepancy between load added now by new customers and load added "now" by existing customers under our proposal (refer to paragraph 3.65),[33] but

(b) create a discrepancy between load added now and load added prior to the implementation of the TPM.

3.67. As noted in previous decision papers, the Authority recognises there is no perfect allocator for residual charges, as it is impossible to eliminate all effects of the charge on a customer's decision-making.[34] Load customers have differing characteristics and any metric will inevitably be preferred by some parties and not others. However, the Authority considers on balance, this change for new customers would be beneficial in the context of addressing the issue discussed above at paragraph 3.63, as we are focused on ensuring a level playing field:

(a) between one existing transmission customer and another that are choosing to compete with new investments (including in emerging technology)

(b) between existing and new transmission customers choosing to compete with new investments (including in emerging technology).

3.68. We acknowledge that this change may have effects on competition between transmission customers who choose to compete using current technologies (including sunk investments) and new customers investing in emerging technologies. Eg, a new industrial customer might have an advantage over an existing industrial customer with which it is competing, or vice versa. However, this scenario appears likely to eventuate less frequently than the scenarios noted in the preceding paragraph, noting that the connection of new grid-connected industrial load as a new transmission customer is not a frequent event.

3.69. This approach is a change from using capacity (AMD) as a proxy for customers' size/ability to pay, as the new approach uses total consumption instead. However,

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33 Noting that the new load will have a lagged effect on residual charge allocation, as will be the case for any change in consumption for any load customer.

34 See, for instance, paragraph 10.48 of the [2020 Guidelines decision paper (ea.govt.nz)](ea.govt.nz).

the Authority has always recognised that consumption is a valid proxy for a customer's size/ability to pay. (The reason the initial allocation for existing customers was not based on consumption was a concern about material adverse impact on existing industrial customers.) So the proposed new approach (which does not materially impact existing industrials) remains consistent with the original rationale for the residual charge.

3.70. The Authority is open to considering alternative views on these matters. We invite submissions on alternative proposals that would address the identified issues.

Q3. Do you agree with the proposed amendments to the residual charge annual adjustment?

Q4. The residual charge is intended to be non-distortionary and this proposed amendment is aimed at levelling the playing field and avoiding inefficient investment (irrespective of technology). Are there any other approaches the Authority should consider to address this issue?

Illustration of impact

3.71. To further illustrate the impact of the identified residual charge issues and the proposed solution we have:

(a) modelled the indicative increase in residual charges for existing customers increasing their consumption by an additional 10,000MWh per year.

(b) considered the expected residual charges that hypothetical new customers would face.[35]

(c) modelled the indicative rebalancing of residual charges for existing customers between the status quo and proposal if implemented in PY26/27.

3.72. The modelling for (a) and (c) above is published alongside this paper.

Modelling of indicative residual charge increases for new customers

3.73. Our modelling of indicative residual charges for existing customers illustrates the incremental annual residual charge from an increase in energy consumption for existing customers of 10,000 MWh per year. This figure is based on the expected increase to total gross energy from a new BESS, assuming a 100 MW BESS with a 200 MWh storage capacity, operating an average of 1.5 complete cycles per day, with a loss factor of just below 10%). However, the results are the same for any increase in energy consumption, whether it is new load, BESS or otherwise, or just an increase in consumption by existing assets.

35 For new customers that, due to the lags with residual charges, were assessed to not have residual charges in the indicative pricing, we have not modelled the impacts because the relevant information is not included in the published workbook.

3.74. The modelling summarised in Table 2 below illustrates:

(a) the incremental cost of adding 10,000 MWh in consumption is broadly similar for distributors, estimated to be between $90,000 and $145,000 in annual residual charges, with a median value of $112,000

(b) the incremental cost range is wider for direct connects, but the median value of $85,000 in additional residual charges is lower than for lines businesses

(c) the incremental cost range for generators is much wider, and the median incremental cost is almost 10 times that of lines businesses.

Table 2: Median incremental annual residual charge for additional 10,000MWh of energy consumption

Customer type	Status quo	Proposal
Distributor	$112,082	$109,296
Direct connect	$85,563	$109,296
Generator	$1,044,804	$109,296

Source: Electricity Authority modelling.

3.75. We have not modelled a separate scenario where energy decreases below baseline consumption levels ($ATGE_{baseline}$). In these situations, our proposal is to retain the status quo approach to changes in consumption.

3.76. The modelling summarised in table 2 uses several important assumptions, the modelling:

(a) builds on Transpower's indicative prices for PY22/23.

(b) ignores the long lag with which changes in consumption feed through to charges (by assuming the change in demand takes immediate effect)

(c) assumes there are no other changes to the customer's energy consumption

(d) assumes the residual charge allocation rate (the $/kW figure applied to a customer's AMDR) remains constant.

Modelling of indicative residual charge increases for hypothetical new customers

3.77. Table 3 below shows different types of new load that are likely to have different load factors, and therefore different estimated AMDR and ATGE baselines. As such, if these loads are connected as new transmission customers, their residual charge per MWh of expected consumption will vary. However, under the proposal, their residual charge per MWh of consumption would be consistent across all load types, and also consistent with the increased residual charge existing customers will face.

(a) Under the status quo, the residual charge allocation is in proportion to the new load's estimated AMDR. New load with a low load factor will therefore have a high residual charge allocation per MWh if it connects as a new customer, so it is more likely to benefit from co-locating with other transmission customers (particularly those with high load factors), relative to new load that has a high load factor.

(b) Under the proposal, the residual charge allocation is proportionate to the new load's estimated ATGE. This means any increase in consumption, whether a new load or otherwise, would result in the same increase to the residual charge.

Table 3: Residual charge for different types of new load

New load type and assumed characteristics	Residual charge (status quo)		Residual charge (proposal)	
	Total $	$/MWh	Total $	$/MWh
EV fast-charging hub ADMR baseline: 6 MW ATGE baseline: 1 GWh/yr Load factor: very low (2%)	$322,740	$322.74	$10,930	$10.93
BESS ADMR baseline: 10 MW ATGE baseline: 10 GWh/yr Load factor: low (11%)	$537,900	$53.79	$109,296	$10.93
Electrolyser ADMR baseline: 10 MW ATGE baseline: 35 GWh/yr Load factor: medium (40%)	$537,900	$15.37	$382,537	$10.93
Data centre ADMR baseline: 25 MW ATGE baseline: 185 GWh/yr Load factor: high (84%)	$1,344,750	$7.27	$2,021,981	$10.93

3.78. For example, while a new BESS[36] has a relatively low load factor, it is still higher than the load factor of a median generator. This means that under the status quo, a median generator adding this BESS would pay over $1 million per year in residual charge increases (see Table 2). However, if the generator connected the BESS as a new customer, it would cost approximately $500,000 (see Table 3). If the BESS was connected through an existing lines business its increase in residual charges would be smaller (assuming the values would be similar to the medians in table 2). Under the proposal, the new BESS would cost around $100,000 per year in increased residual charges, regardless of where or by whom it is connected.

3.79. Overall, the Authority expects a new transmission customer connecting a BESS, an EV fast-charging hub or an electrolyser to pay a lower residual charge under the

[36] The BESS in Table 3 has the same energy consumption (losses) as the additional energy consumption figure used in Table 2, (ie, 10,000MWh/yr). This is based on a 100MW battery with a storage capacity of 200MWh, running approximately 1.4 cycles per day, with a loss factor of 10%. We also assume that Transpower applies this 10% loss factor to the battery's nameplate charging capacity when estimating the battery's AMDR (so the AMDR is based on the battery's anytime maximum losses, rather than its anytime maximum charging demand), as per clause 70(2) of the TPM.

proposal than they would under the status quo. This is because the load factors of these new loads tend to be lower than the weighted average load factor of all transmission customers. On the other hand, we expect a data centre or other high load factor new load), would pay a higher residual charge under the proposal. The Authority is comfortable with these outcomes, as the residual charge of such new customers will still reflect the relative size of such customers, and will avoid creating perverse incentives that could ultimately result in higher electricity prices for consumers.

Estimated impact on residual charges for existing transmission customers

3.80. The proposed change to the residual charge allocations with a common load factor for increases in load is expected to lead to some rebalancing of residual charges when implemented. We have therefore modelled indicative estimates of the differences between the status quo and the proposal in pricing year 2026/27.

3.81. From 2026-27, the proposed amendment would affect the residual charges payable by each existing transmission customer whose lagged consumption exceeds its baseline consumption level. For such a customer, its consumption growth (ie, the amount by which lagged consumption exceeds baseline) would be added to its residual charge allocator using the new uniform conversion factor. This proposed change is be expected to lead to a rebalancing of residual charges.

3.82. We have estimated the impact of the proposed amendment on residual charges for existing transmission customers. We are modelling customers' indicative charges for pricing year 2022/23, for which recoverable residual revenue was $454m, and using that information, modelling the indicative allocation of the revenue in pricing year 2026/27 using indicative energy offtake information that will be reflected in the allocations for that year.[37]

3.83. A summary of the residual charge allocation between the three main consumer groups (distribution lines businesses, generators and direct connect consumers) using the current TPM (status quo) and the proposed approach is provided below.

Summary by Customer Group	2027 - Status Quo	2027 - Proposal	Status Quo Vs Proposal $	2027 - Status Quo vs Proposal %
Lines Business	399,374,199	399,534,771	160,572	0.04%
Generator	6,065,287	5,821,611	(243,675)	-4.0%
Direct Connect	48,879,714	48,962,817	83,103	0.2%
	454,319,200	**454,319,200**	**0**	

3.84. The proposal will result in minor rebalancing of charges between customers. The rebalancing between customers is as follows:

(a) Generators' indicative residual charges *reducing* by just over $240,000 in aggregate. Most generators receive either a reduction or no change to their residual charge, and a small number of generators incur a small increase.

[37] We have not modelled the residual revenue that Transpower provided in its indicative pricing for RCP4 ($622m). If residual revenue is higher, all impacts are proportionately higher than the impacts shown in this paper. RCP4 Indicative Transmission Charges - Indexed RAB.xlsx (live.com)

These changes are relatively small compared to the size of most of the affected generators.

(b) Distribution lines businesses' overall residual charges *increased* by $160,000 in aggregate, or by only 0.04%. A small number of distributors' charges went own.

(c) Direct connect customers' overall residual charges *increased* by $83,000 in aggregate, with all direct connect consumers experiencing an increase. However, the increase was typically less than 0.2% of direct connects' residual charges. The only exception was Beach Energy Resources, whose charge would increase by 6.4%, or around $40,000.

3.85. An expanded set of tables and charts describing these indicative estimates, alongside a discussion of important simplifying assumptions, is provided in Appendix D.

4. Regulatory statement for the proposed amendments

4.1. In this section we provide a regulatory statement for the two proposed amendments in this consultation paper:

(a) connection charges for shared connection assets

(b) residual charge allocation

Connection charges for shared connection assets

Objectives of the proposed amendment

4.2. The objective of the proposed Code amendments is to promote competition by helping to level the playing field for BESS and similar technologies compared to other generators. The proposed change is intended to remove distortions to incentives and promote efficient investment, supporting the electrification of the economy and the introduction of new and emerging technologies such as grid-scale BESS. This would ensure consistency with the Authority's main statutory objective: to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers.

Q5. Do you agree with the objectives of the proposed amendment? If not, why not?

The proposed amendment

4.3. The Authority proposes amending clause 32 of the TPM to change the calculation for allocating connection charges at shared connection assets from calculating both anytime maximum demand and anytime maximum injection (AMDIC) to calculating it using the greater of the anytime maximum demand (AMDC) or injection (AMIC).

4.4. The drafting of the proposed amendment is in Appendix A of this paper.

The proposed amendment's benefits are expected to outweigh the costs

4.5. The Authority has assessed the benefits and costs of the proposed Code amendments and expects them to deliver a net benefit.

4.6. Relative to the status quo arrangements the main expected incremental benefit of the proposed amendments is to remove a potential barrier to competition by ensuring a level playing field with respect to transmission costs for different generation technologies.[38]

4.7. It does this by ensuring that all technologies, including BESS, are charged on a consistent basis: based on maximum injection and demand capacity. This approach prevents redundant charges and aligns the cost of shared connection assets with those of similar-sized investments.

[38] The relevant markets where benefits may arise are the wholesale market as well as markets adjacent to the wholesale market such as the market for ancillary services.

4.8. The proposed Code amendment may also have other benefits, to the extent transmission charges relating to shared connection assets are a material consideration in investment decisions by:

i. reducing a barrier to investments due to higher ongoing costs related to shared connection costs for BESS and other technologies.

ii. to the extent BESS would be deterred by the shared connection costs under the current TPM (alongside other factors) the amendment may contribute to enhancing grid efficiency by:

(a) facilitating the integration of BESS, improving grid reliability

(b) deferring the need for investment in more costly alternatives to BESS, potentially including more costly generation and/or grid infrastructure, ultimately resulting in relatively lower electricity prices for consumers.

4.9. The expected incremental costs of the proposed amendments are the administrative costs of Transpower changing its transmission pricing system to implement the change. The implementation cost is expected to be modest. One of the transitional implementation costs would be Transpower's additional explanation of the change in charging approach to existing customers. To allow sufficient time for Transpower's consultation on how it will implement the change and reduce the risks associated with implementation on a compressed timeframe the change would not take effect until PY2026.

4.10. We acknowledge the rebalancing of charges for a small number of existing customers may impact the durability of the TPM. This risk is mitigated by consulting on this proposed amendment.

4.11. In summary, the change may mean that wholesale costs are lower than they otherwise would be and/or the quality (including reliability) provided to consumers may be greater than it otherwise would be. We have limited information on how competition in the market including as a result of emerging technologies is expected to evolve over time, and the extent to which competition will be driven by investments by customers at existing connection locations.

4.12. We therefore have not attempted to quantify the benefits associated with this change, but the Authority considers the expected incremental benefits to outweigh the expected incremental cost.

Q6. Do you agree the benefits of the proposed amendment outweigh its costs?

The Authority has identified other means for addressing the objectives

4.13. The Authority considered two alternative options for addressing the objectives:

(a) changing the allocator that applies during the initial two-year period after connection, so that the allocator for that period is the sum of injection and offtake (with no change to the allocator that applies after the initial two-year period) so the allocator is the same for each of the two periods

(b) applying the proposed amendment to BESS only and continuing to apply the status quo to all other customers.

Applying status quo from when a customer connects at a shared connection location

4.14. The option described at paragraph 4.13(a) would change the allocator that applies during the initial two-year period after connection, so that the allocator for that period is the sum of anytime maximum demand and anytime maximum injection (AMDIC) (with no change to the allocator that applies after the initial two-year period) so the allocator is the same for each of the two periods. In this option we would take the view that the connection charge is based not on maximum capacity but the capacity of both injection and offtake.

Applying status quo to all customers except batteries

4.15. The Authority is aware that currently the connection charge allocation issue described in this paper has the most material impact on BESS. The option described at paragraph 4.13(b) would amend the calculation of the allocator at shared connection assets for BESS only and leave the allocator for all other customers unchanged. That is, at shared connection assets, the allocator for BESS would be based on the greater of the anytime maximum demand (AMDC) or injection (AMIC), but for all other customers the allocator would continue to be based on the sum of anytime maximum demand and anytime maximum injection (AMDIC) in the period after the initial two-year period..

The proposed amendment is preferred to other options

4.16. The Authority has evaluated the other means for addressing the objectives and considers its proposal better achieves its main statutory objective.

4.17. The Authority's view is that connection charges should be based on capacity. The view is that connection charges should be determined by the maximum capacity that a transmission customer needs to either inject into or offtake from the grid.

4.18. Therefore, the Authority considers that the option described at paragraph 4.13(a) is not appropriate given that it is not based on the maximum capacity used by a customer and as such would not create a level playing field.

4.19. The option described at paragraph 4.13(b) would address the main issue with the connection charges for shared connection assets that are expected for batteries. However, this option would not future-proof the TPM as other technologies and configurations emerge.

4.20. The Authority considers that this option provides less certainty than the proposed approach and in future further revisions would likely be required as other technologies and configurations emerge.

Q7. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.

The proposed amendment complies with the intent of the 2020 TPM Guidelines

4.21. The 2020 TPM Guidelines retained the approach of the 2006 Guidelines on connection charges, as they were considered largely consistent with efficient charging.

4.22. The 'Authority's intent' section of the TPM 2020 Guidelines states: '*the purpose of the connection charge is to charge each designated transmission customer to recover the cost of the connection investments that connect that designated transmission customer's assets to the interconnected grid.'* Clause 11 then provides that: '*[t]he TPM must provide for the costs of connection investments to be recovered from those designated transmission customers whose assets are connected to the assets forming part of those connection investments.'*

4.23. The proposed amendment is in line with the intent of the 2020 TPM guidelines as each transmission customer will be charged a connection charge and such charges collectively recover the cost of the connection investments. It is also consistent with clause 11 as costs will still be recovered from customers connected to connection assets. However, the amendment would better meet the Authority's statutory objective by changing the allocation of charges for customers with shared connection assets to take into consideration newer technologies that were not connected when the TPM was developed. This would allow a level playing field for all technologies.

The proposed amendment complies with section 32(1) of the Act

4.24. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to the direct dealings between participants and these consumers – it therefore does not apply here.

4.25. Section 32(1) of the Act says the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

4.26. The Authority considers the proposed amendment is necessary or desirable to promote competition and efficient operation of the electricity industry through avoiding distortion to investment incentives and to competition between designated transmission customers. This is done by ensuring that connection charges reflect the maximum power capacity that a transmission customer needs to either inject into or offtake from the grid, as set out in section 2 of this paper.

4.27. Additionally, this proposed amendment promotes the reliable supply of electricity to consumers given that batteries have reliability benefits for meeting peak demand.

Q8. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

The Authority has applied Code amendment principles

4.28. When considering amendments to the Code, the Authority's consultation charter provides that to provide greater predictability about decision-making on Code amendments the Authority applies certain principles. Table 1 (below) describes the application of these principles to the proposal.

Table 1: Code amendment principles

Principle	
Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	The Authority considers that the evidence discussed in this paper sets out a clear case for amending the TPM.
Costs and benefits are summarised: The Authority is required to include with any Code amendment proposal an evaluation of the costs and benefits of the proposed amendment. The Authority will also include a summary of this evaluation.	A summary of Authority's evaluation of the costs and benefits of this proposal has been provided in this paper.
Preference for small-scale 'trial and error' options	Not applicable. Principles 3-7 only apply where analysis demonstrates a clear benefit to a Code amendment proposal, but there is no clear best option in terms of a solution. The Authority considers that there is a clear best option in this case.
Preference for greater competition	Not applicable.
Preference for market solutions	Not applicable.
Preference for flexibility to allow innovation	Not applicable.
Preference for non-prescriptive options	Not applicable.

Residual charge annual adjustments

Objectives of the proposed amendment

4.29. The objective of the proposed Code amendment is to ensure residual charge allocation is to address an issue with how a customer's load factor disproportionately affects how the residual charge is adjusted based on lagged annual changes to a customer's energy consumption (including the connection of new load). The proposed changes are intended to remove distortions to incentives and promote efficient investment, supporting the electrification of the economy and the introduction of new and emerging technologies such as grid-scale BESS. This would ensure consistency with the Authority's main statutory objective: to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers.

Q9. Do you agree with the objectives of the proposed amendment? If not, why not?

The proposed amendment

4.30. The proposed amendment:

(a) adopts a 'uniform conversion factor' when converting any customer's change in energy consumption (in MWh) to a change in their residual charge allocator (AMDR, in MW), where the customer's lagged consumption is above its baseline consumption level.

(b) changes the calculation of a new customer's initial residual charge so that it is determined based on its estimated energy consumption and converted to MW using the average load factor of existing customers.

4.31. This is explained in detail in section 3 above.

4.32. The drafting of the proposed amendment is contained in Appendix B.

The proposed amendment's benefits are expected to outweigh the costs

4.33. The Authority has assessed the benefits and costs of the proposed Code amendment and expects benefits to far outweigh the costs.

4.34. Relative to the status quo arrangements, the primary expected incremental benefit of the proposed amendments is that it would remove an inefficiency that exists under the status quo. It would do this by ensuring that the same change in energy consumption results in the same incremental change in residual charges (where lagged consumption exceeds baseline consumption), irrespective of the transmission customer's load factor (and also therefore irrespective of whether a new load is connected to the grid directly or via a distribution network).

4.35. The Code change may also contribute to other benefits:

(a) To the extent that residual charges are material considerations in investment decisions, the proposal may reduce barriers for customers with high load factors to invest in new load (or otherwise increase their consumption), therefore increasing competition.

(b) To the extent that new or existing customers would be deterred from investing in BESS by higher residual charges under the status quo, the amendment may contribute to enhancing grid efficiency by facilitating the integration of BESS, improving grid reliability

(c) potentially avoiding inefficient incentives for customers to make investment decisions that would be more costly than would otherwise be the case, ultimately resulting in relatively lower electricity prices for consumers.

4.36. The expected incremental costs of the proposed amendments are the administrative costs of Transpower changing its transmission pricing system to implement the change. The implementation cost is expected to be modest.

4.37. This change may put transmission customers who choose to compete using current technologies (including sunk investments), at a disadvantage compared with new customers investing in emerging technologies. Eg, a new industrial customer might have an advantage over an existing industrial customer with which it is competing, or vice versa. However, this scenario appears likely to eventuate less frequently than the other scenarios, noting that the connection of new grid-connected industrial load as a new transmission customer is not a frequent event.

4.38. The Authority considers that the expected incremental benefits outweigh the expected incremental cost.

Q10. Do you agree the benefits of the proposed amendment outweigh its costs?

The Authority has identified another option for addressing the objectives

4.39. The Authority considered an alternative approach which involves applying a cap to residual charges, so no customer – even those with very low load factors – would pay more than a fixed rate (in $/MWh) for increases to their consumption. The alternative option would apply a fixed rate to customers whose individual conversion factor is above a certain limit.[39]

The proposed amendment is preferred to other option

4.40. The Authority has evaluated the other means for addressing the objectives and considers its proposal better promotes its statutory objectives.

4.41. The Authority's objective is to address the issue with how the residual charge is adjusted based on lagged annual changes to a customer's energy consumption (including the connection of new load) based on the customer's load factor. It is important any amendment removes inefficiencies that are present under status quo.

4.42. Whilst a cap would address the more extreme outliers, such as customers with very low load factors who face very high residual charge increases relative to their consumption, it would continue to have considerable disparities between customers, ie, those with capped charges and those without.

4.43. The alternative option (a cap) provides a less effective and less principled solution than the Authority's proposed solution. Using a uniform conversion factor to apply to all additional load would level the playing field through removing the discrepancies we see under the alternative approach and under the status quo.

4.44. The residual charge is meant to be a fixed charge and there is no rationale for why we should see discrepancies in charges for additional load of the same size,

4.45. Therefore, it has been determined that a cap is not an appropriate alternative solution given that the proposed amendment achieves the objective in a more effective and efficient way.

Q11. Do you agree the proposed amendment is preferable to the other option? If you disagree, please explain your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.

[39] The conversion factor used in these cases would be higher than the uniform conversion factor used in the Authority's preferred option, as it would reflect a maximum incremental residual charge, rather than a weighted averaged one.

The proposed amendment complies with the intent of the 2020 TPM Guidelines

4.46. The Authority considers that, while its proposal differs in its detail from the particular requirements of the TPM guidelines, it is nevertheless consistent with them by virtue of clause 2 as it ensures that the TPM better meets the intent of the Guidelines and the Authority's statutory objective.

4.47. Clause 30 of the TPM guidelines provides a formula for how residual charges for customers are to be adjusted – it is this formula which is currently reflected in the TPM. By adjusting the TPM to reduce the impact of a customer's load factor on the adjustments to the residual charge, the Authority would be differing from the approach set out in clause 30 of the TPM guidelines. Clause 33(c) further provides that processes for allocating residual charges in respect of new customers must ensure that charges for new customers are equivalent to the charges Transpower considers would have been payable had the new customer been fully operational from 1 July 2014. Again, this would not be the case under the Authority's proposal.

4.48. Nevertheless, the Authority considers that its proposal is consistent with the TPM guidelines. Clause 2 of the TPM guidelines provides that the TPM may differ in its details from the particular requirements of the TPM guidelines (but not their intent) if doing so would better meet the Authority's statutory objective than complying with the TPM guidelines in their entirety.

4.49. The 'Authority's intent' section of the TPM guidelines states: "*the purpose of the residual charge is to provide a mechanism to ensure that Transpower can recover up to its recoverable revenue in any pricing year in a way which is designed to minimise any effect on designated transmission customers' decision-making."* The proposed amendment is in line with the intent section of the guidelines.

4.50. The amendment to the residual charge annual adjustment would improve how transmission customers are charged for new load and/or changes in consumption. This approach aligns with the guidelines by guaranteeing Transpower's revenue recovery while minimising the impact on customers' decision-making but while also maintaining efficient charging. The Authority further considers this approach is consistent with its statutory objective for the reasons set out below. It therefore considers the requirements of clause 2 of the TPM guidelines to be satisfied.

The proposed amendment complies with section 32(1) of the Act

4.51. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to the direct dealings between participants and these consumers – it does not apply to this proposed amendment.

4.52. Section 32(1) of the Act says the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

4.53. The Authority considers the proposed amendment is necessary or desirable to promote competition and efficient operation of the electricity industry. As further set out in section 3 above, it would remove a distortion where different customers may face different costs from changing consumption patterns, investment in new load and/or investment in emerging technologies, which may slow down the efficient adoption of new technologies and distort competition.

Q12. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

The Authority has applied Code amendment principles

4.54. When considering amendments to the Code, the Authority's consultation charter provides that to provide greater predictability about decision-making on Code amendments the Authority applies certain principles. Table 1 (below) describes the application of these principles to the proposal.

Table 1: Code amendment principles

Principle	
Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	The Authority considers that the evidence discussed in this paper sets out a clear case for amending the TPM.
Costs and benefits are summarised: The Authority is required to include with any Code amendment proposal an evaluation of the costs and benefits of the proposed amendment. The Authority will also include a summary of this evaluation.	A summary of Authority's evaluation of the costs and benefits of this proposal has been provided in this paper.
Preference for small-scale 'trial and error' options	Not applicable. Principles 3-7 only apply where analysis demonstrates a clear benefit to a Code amendment proposal, but there is no clear best option in terms of a solution. The Authority considers that there is a clear best option in this case.
Preference for greater competition	Not applicable.
Preference for market solutions	Not applicable.
Preference for flexibility to allow innovation	Not applicable.
Preference for non-prescriptive options	Not applicable.
Risk reporting	Not applicable.

Appendix A Proposed amendment to provisions regarding connection charges

Current clause	Proposed amendment
32 Connection Customer Allocations (1) Subject to subclause (5) and clause 33, a customer's connection customer allocation for a connection asset, connection location and pricing year (CA1) is calculated as follows if the connection asset is— a. for 1 connection location only; and b. not a mixed connection asset: $CA_1 = AMDIC / AMDIC_{total}$ Where **AMDIC** is the total of the customer's AMDC and AMIC at the connection location for the pricing year **AMDIC**$_{total}$ is the total of all customers' AMDCs and AMICs at the connection location for the pricing year.	**32 Connection Customer Allocations** (1) Subject to subclause (5) and clause 33, a customer's (customer c's) connection customer allocation for a connection asset, connection location and pricing year (CA1) is calculated as follows if the connection asset is— a. for 1 connection location only; and b. not a mixed connection asset: $CA_1 = \frac{AMDIC_c}{\sum_j AMDIC_j}$¶ Where J is the total number of customers at the connection location for the pricing year, including customer c, each such customer being customer j AMDICc is customer c's AMDC or AMIC at the connection location for the pricing year, whichever is greater AMDICj is customer j's AMDC or AMIC at the connection location for the pricing year, whichever is greater (2) Subject to subclause (5) and clause 33, a customer's (customer c's) connection customer allocation for a connection asset, connection

Current clause	Proposed amendment
(2) Subject to subclause (5) and clause 33, a customer's connection customer allocation for a connection asset, connection location and pricing year (CA2+) is calculated as follows if the connection asset is— a. for 2 or more connection locations, being the set of connection locations L; and b. not a mixed connection asset: $CA_{2+} = AMDIC / AMDICL_{total}$ where **AMDIC** is the total of the customer's AMDC and AMIC at the connection location for the pricing year **AMDICL** total is the total of all customers' AMDCs and AMICs at all connection locations in the set of connection locations L for the pricing year. (3) Subject to subclauses (4) and (5) and clause 33, a customer's connection customer allocation for a connection asset, connection location and pricing year (CAmixed) is calculated as follows if the connection asset is a mixed connection asset: $CAmixed = AMDIC/C$ where	location (connection location x) and pricing year (CA2+) is calculated as follows if the connection asset is— a. for 2 or more connection locations, being the set of connection locations L; and b. not a mixed connection asset: $$CA_{2+} = \frac{AMDIC_c}{\sum_l \sum_j AMDIC_{jl}}$$¶ where J is the total number of customers, including customer c, at connection location l (being a connection location in the set L, including connection location x) for the pricing year, each such customer being customer j AMDICc is customer c's AMDC or AMIC at connection location x for the pricing year, whichever is greater AMDICjl is customer j's AMDC or AMIC at connection location l for the pricing year, whichever is greater. (3) Subject to subclauses (4) and (5) and clause 33, a customer's connection customer allocation for a connection asset, connection location and pricing year (CAmixed) is calculated as follows if the connection asset is a mixed connection asset: $$CA_{mixed} = \frac{AMDIC}{C}$$¶ where

Current clause	Proposed amendment
AMDIC is the total of the customer's AMDC and AMIC at the connection location for the pricing year C is the capacity of the connection asset at the end of CMP A for the pricing year. (4) If the sum of all customers' connection customer allocations for a mixed connection asset and pricing year is greater than 1, Transpower must scale down all of the connection customer allocations on a pro rata basis so that they sum to 1. (5) If a connection asset is— a. an investment agreement asset provided under an investment agreement with a customer; and b. for more than 1 connection location, or for 1 connection location at which there is more than 1 customer, then the calculation of the connection customer allocations for the connection asset and connection locations is subject to any provisions in the investment agreement that alter the customer's connection customer allocation for the connection asset and connection locations	AMDIC is the customer's AMDC or AMIC at the connection location for the pricing year, whichever is greater C is the capacity of the connection asset at the end of CMP A for the pricing year. (4) If the sum of all customers' connection customer allocations for a mixed connection asset and pricing year is greater than 1, Transpower must scale down all of the connection customer allocations on a pro rata basis so that they sum to 1. (5) If a connection asset is— a. an investment agreement asset provided under an investment agreement with a customer; and b. for more than 1 connection location, or for 1 connection location at which there is more than 1 customer, then the calculation of the connection customer allocations for the connection asset and connection locations is subject to any provisions in the investment agreement that alter the customer's connection customer allocation for the connection asset and connection locations

Q13. Do you have any comments on the drafting of the proposed amendment in Appendix A?

Appendix B Proposed amendment for residual charge

Current Code drafting	Code drafting to implement the alternative
69 Anytime Maximum Demand (Residual)	**69 Anytime Maximum Demand (Residual)**
(1) A **load customer's AMDR** for **pricing year** n ($AMDR_n$) is—	(1) A **load customer's AMDR** for **pricing year** n ($AMDR_n$) is—
(a) 0 if the **load customer** became a **customer** at or after the start of **financial year** n-4; or	(a) 0 if the **load customer** became a **customer** at or after the start of **financial year** n-4; or
(b) calculated as follows if the **load customer** became a **customer** before the start of **financial year** n-4 and at or after the start of **financial year** n-8:	(b) calculated as follows if the **load customer** became a **customer** before the start of **financial year** n-4 and at or after the start of **financial year** n-8:
$AMDR_n = AMDR_{baseline} \times \left(\frac{n-m}{4} - 1\right)$	$AMDR_n = AMDR_{baseline} \times \left(\frac{n-m}{4} - 1\right)$
where	where
m — is the **financial year** during which the **load customer** became a **customer**	m — is the **financial year** during which the **load customer** became a **customer**
$AMDR_{baseline}$ — is the **load customer's AMDR** baseline calculated or estimated under clause 70; or	$AMDR_{baseline}$ — is the **load customer's AMDR** baseline calculated or estimated under clause 70; or
(c) otherwise, calculated as follows:	(c) otherwise, calculated as follows:
$AMDR_n = AMDR_{baseline} \times RCAF_n$	$AMDR_n = AMDR_{baseline} + RCAF_n$
where	where

Current Code drafting	Code drafting to implement the alternative
$AMDR_{baseline}$ is the **load customer's AMDR** baseline calculated or estimated under clause 70 $RCAF_n$ is the **load customer's RCAF** for **pricing year** n.	$AMDR_{baseline}$ is the **load customer's AMDR** baseline calculated or estimated under clause 70 $RCAF_n$ is the **load customer's RCAF** for **pricing year** n.
70 Anytime Maximum Demand (Residual) Baseline (1) Subject to subclause 72(1), a **pre-existing load customer's AMDR** baseline ($AMDR_{baseline}$) is calculated as follows: $$AMDR_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017}\sum_{l} MGD_{ln}$$ where MGD_{ln} is the **pre-existing load customer's maximum gross demand** for **connection location** l and **financial year** n. (2) A **recent load customer's AMDR** baseline— (a) is estimated by **Transpower** as if the **recent load customer's assets** were fully operational from the start of **CMP D** and taking into account— (i) the type and capacity of the **recent load customer's assets**; and (ii) the **AMDR** baselines for any other **load customers** with **assets** of the same or a similar type as the **recent load customer's assets**; and (iii) any available information about the **recent load customer's maximum gross demand**, but excluding any contribution to the **recent load customer's maximum gross demand** from the charging or discharging of **large battery storage** other than the **battery storage's** energy losses; and (b) may be re-estimated by Transpower under clause 73.	**70 Anytime Maximum Demand (Residual) Baseline** (1) Subject to subclause 72(1), a **pre-existing load customer's AMDR** baseline ($AMDR_{baseline}$) is calculated as follows: $$AMDR_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017}\sum_{l} MGD_{ln}$$ where MGD_{ln} is the **pre-existing load customer's maximum gross demand** for **connection location** l and **financial year** n. (2) A **recent load customer's AMDR** baseline is calculated as follows if it has not already been estimated by **Transpower** under a previous version of this **transmission pricing methodology**: $$AMDR_{baseline} = ATGE_{baseline}\ x\ \frac{AMDR_{baseline\ total}}{ATGE_{baseline\ total}}$$ where $ATGE_{baseline}$ is the **load customer's** average **total gross energy** baseline estimated under clause 71(5).

Current Code drafting	Code drafting to implement the alternative
	$AMDR_{baseline\ total}$ is the sum of all current **pre-existing load customers' AMDR** baselines calculated under clause 70(1) $ATGE_{baseline\ total}$ is the sum of all current **pre-existing load customers'** average **total gross energy** baselines calculated under clause 71(4).
71 Residual Charge Adjustment Factor (1) A **load customer's RCAF** for **pricing year** n ($RCAF_n$) is calculated as follows: $$RCAF_n = \frac{LATGE_n}{ATGE_{baseline}}$$ where $LATGE_n$ is the **load customer's** lagged average **total gross energy** for **pricing year** n calculated under subclause (2) $ATGE_{baseline}$ is the **load customer's** average **total gross energy** baseline calculated or estimated under subclause (4) or (5).	**71 Residual Charge Adjustment Factor** (1) A **load customer's RCAF** for **pricing year** n ($RCAF_n$) is calculated: (a) if the **load customer's** $LATGE_n$ is equal to or higher than the **load customer's** $ATGE_{baseline}$, as follows: $$RCAF_n = (LATGE_n - ATGE_{baseline})\ x\ \frac{AMDR_{baseline\ total}}{ATGE_{baseline\ total}}$$ where $LATGE_n$ is the **load customer's** lagged average **total gross energy** for **pricing year** n calculated under subclause (2) $ATGE_{baseline}$ is the **load customer's** average **total gross energy** baseline calculated or estimated under subclause (4) or (5). $AMDR_{baseline\ total}$ is the sum of all relevant **load customers' AMDR** baselines calculated or estimated under clause 70, where a relevant

Current Code drafting	Code drafting to implement the alternative
	load customer is a current **load customer** whose **AMDR** is calculated under clause 69(1)(c) $ATGE_{baseline\ total}$ is the sum of all relevant **load customers'** average **total gross energy** baselines calculated or estimated under subclause (4) or (5), where a relevant **load customer** is a current **load customer** whose **AMDR** is calculated under clause 69(1)(c). (b) if the **load customer's** $LATGE_n$ is lower than the **load customer's** $ATGE_{baseline}$, as follows: $$RCAF_n = (LATGE_n - ATGE_{baseline})\ x\ \frac{AMDR_{baseline}}{ATGE_{baseline}}$$ where $LATGE_n$ is the **load customer's** lagged average **total gross energy** for **pricing year** n calculated under subclause (2) $ATGE_{baseline}$ is the **load customer's** average **total gross energy** baseline calculated or estimated under subclause (4) or (5). $AMDR_{baseline}$ is the **load customer's AMDR** baseline calculated or estimated under clause 70

Current Code drafting	Code drafting to implement the alternative
(2) A **load customer's** lagged average **total gross energy** for **pricing year** n ($LATGE_n$) is calculated as follows: $$LATGE_n = \frac{1}{4}\sum_{m=n-8}^{n-5} F_m \times TGE_m$$ where F_m is— (a) if— (i) the **load customer** is a **pre-existing load customer**; and (ii) there has been one or more **reduction events** for the **load customer** that occurred after the end of **financial year** m, the **reduction event** adjustment factor for the **load customer** and **financial year** m calculated under subclause (3); or (b) otherwise, 1 TGE_m is— (a) if— (i) the **load customer** is a **pre-existing load customer**; and (ii) there has been one or more **reduction events** for the **load customer** that occurred during **financial year** m, $ATGE_{after}$ as defined in subclause (3), immediately after the most recent such **reduction event**; or (b) otherwise, the **load customer's total gross energy** for **financial year** m.	2) A **load customer's** lagged average **total gross energy** for **pricing year** n ($LATGE_n$) is calculated as follows: $$LATGE_n = \frac{1}{4}\sum_{m=n-8}^{n-5} F_m \times TGE_m$$ where F_m is— (a) if— (i) the **load customer** is a **pre-existing load customer**; and (ii) there has been one or more **reduction events** for the **load customer** that occurred after the end of **financial year** m, the **reduction event** adjustment factor for the **load customer** and **financial year** m calculated under subclause (3); or (b) otherwise, 1 TGE_m is— (a) if— (i) the **load customer** is a **pre-existing load customer**; and (ii) there has been one or more **reduction events** for the **load customer** that occurred during **financial year** m, $ATGE_{after}$ as defined in subclause (3), immediately after the most recent such **reduction event**; or (b) otherwise, the **load customer's total gross energy** for **financial year** m.

Current Code drafting	Code drafting to implement the alternative
(3) The **reduction event** adjustment factor for a **load customer** and **financial year** m ($REAF_m$) is calculated as follows: $$REAF_m = 1 - \frac{ATGE_{before} - ATGE_{after}}{ATGE_{before}}$$ where $ATGE_{after}$ is the **load customer's** average **total gross energy** baseline immediately after the reduction under subclause 72(2) for the latest **reduction event** that occurred after the end of **financial year** m $ATGE_{before}$ is the **load customer's** average **total gross energy** baseline immediately before the reduction under subclause 72(2) for the earliest **reduction event** that occurred after the end of **financial year** m.	(3) The **reduction event** adjustment factor for a **load customer** and **financial year** m ($REAF_m$) is calculated as follows: $$REAF_m = 1 - \frac{ATGE_{before} - ATGE_{after}}{ATGE_{before}}$$ where $ATGE_{after}$ is the **load customer's** average **total gross energy** baseline immediately after the reduction under subclause 72(2) for the latest **reduction event** that occurred after the end of **financial year** m $ATGE_{before}$ is the **load customer's** average **total gross energy** baseline immediately before the reduction under subclause 72(2) for the earliest **reduction event** that occurred after the end of **financial year** m.
(4) Subject to subclause 72(2), a **pre-existing load customer's** average **total gross energy** baseline ($ATGE_{baseline}$) is calculated as follows: $$ATGE_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017} TGE_n$$ where TGE_n is the **pre-existing load customer's total gross energy** for **financial year** n.	(4) Subject to subclause 72(2), a **pre-existing load customer's** average **total gross energy** baseline ($ATGE_{baseline}$) is calculated as follows: $$ATGE_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017} TGE_n$$ where TGE_n is the **pre-existing load customer's total gross energy** for **financial year** n.

Current Code drafting	Code drafting to implement the alternative
73 Re-estimating for Recent Load Customers (1) **Transpower** may re-estimate either or both of a **recent load customer's AMDR** baseline and average **total gross energy** baseline— (a) when information is available to **Transpower** about the **recent load customer's maximum gross demand** or **total gross energy** when the **recent load customer's assets** are fully operational, but may only re-estimate each of the **recent load customer's AMDR** baseline and average **total gross energy** baseline under this paragraph once; or (b) if **Transpower** determines information relevant to **Transpower's** estimate of the **recent load customer's AMDR** baseline or average **total gross energy** baseline provided to **Transpower** by or on behalf of the **recent load customer** was false or misleading. (2) To avoid doubt, the purpose of a re-estimation under subclause a is to correct any material under- or over-estimation in **Transpower's** estimate of the **recent load customer's AMDR** baseline or average **total gross energy** baseline.	**73 Re-estimating for Recent Load Customers** (1) **Transpower** may re-estimate either or both of a **recent load customer's AMDR** baseline (if **Transpower** estimated the **recent load customer's AMDR baseline** under a previous version of this **transmission pricing methodology**) and average **total gross energy** baseline— (a) when information is available to **Transpower** about the **recent load customer's maximum gross demand** or **total gross energy** when the **recent load customer's assets** are fully operational, but may only re-estimate each of the **recent load customer's AMDR** baseline and average **total gross energy** baseline under this paragraph once; or (b) if **Transpower** determines information relevant to **Transpower's** estimate of the **recent load customer's AMDR** baseline or average **total gross energy** baseline provided to **Transpower** by or on behalf of the **recent load customer** was false or misleading. (1A) If (a) **Transpower** re-estimates the **recent load customer's** average **total gross energy** baseline under subclause (1); and (b) the **recent load customer's AMDR** baseline was not estimated by **Transpower** under a previous version of this **transmission pricing methodology**, **Transpower** must re-calculate the **recent load customer's AMDR** baseline under subclause 70(2) using the **recent load customer's** re-estimated average **total gross energy** baseline. (2) To avoid doubt, the purpose of a re-estimation under subclause (1) is to correct any material under- or over-estimation in **Transpower's**

Current Code drafting	Code drafting to implement the alternative
	estimate of the **recent load customer's AMDR** baseline or average **total gross energy** baseline.

Q14. Do you have any comments on the drafting of the proposed amendment in Appendix B?

Appendix C Residual charge allocation

C.1. The residual charge allocator in the current TPM is a gross capacity baseline (AMDR) multiplied by an adjustment factor (RCAF) derived from a change in gross energy. This equation can be written, as shown below, to show a capacity baseline to which a change in energy (multiplied by a conversion factor) is added or subtracted.[40]

$$= [baseline] \times [adjustment\ factor]$$

$$= AMDR_{baseline} \times RCAF$$

$$= AMDR_{baseline} \times \frac{LATGE_n}{ATGE_{baseline}}$$

$$= AMDR_{baseline} \times \frac{ATGE_{baseline} + \Delta LATGE_n}{ATGE_{baseline}}$$

$$= AMDR_{baseline} + \Delta LATGE_n \times \frac{AMDR_{baseline}}{ATGE_{baseline}}$$

$$= [baseline] + [lagged\ change\ in\ energy] \times [conversion\ factor]$$

C.2. Rearranging this formula shows the residual charge allocator can be calculated by multiplying the lagged change in energy by a ‘conversion factor’. This conversion factor effectively converts the customer’s lagged change in energy (a MWh figure) into a figure that can be added to or subtracted from the customer’s capacity baseline (a MW figure).

[40] Note that $\Delta LATGE_n$ means the difference between the $LATGE_n$ and the $ATGE_{baseline}$.

Appendix D Estimated impact of proposed amendment on residual charges for existing transmission customers

D.1. In this appendix we provide further information on the indicative impact of the proposed change on residual charges in pricing year (PY) 2026/27 of this paper and the important simplifying assumptions we have made. This appendix supports section 3 of this consultation paper.

Important simplifying assumptions

D.2. Our modelling makes a number of simplifying assumptions that are described below. We also note that these forecasts should not be taken as a prediction of residual charges in PY26/27 (as these will also be influenced by a number of other factors).

a. Our starting point for demand (AMDR) and energy consumption (ATGE) is Transpower's indicative pricing for PY22/23[41] and reconciled offtake data for each network that is published on the Authority's EMI website.[42]

b. We model the residual charge revenue of the PY22/23 indicative pricing ($454m). This does not incorporate any expected increases in residual revenue for RCP4. Transpower's indicative transmission charge modelling estimates residual charge revenue of $622m in PY26/27. If this residual revenue were reflected in the Commerce Commission's final RCP4 decision all estimates in our modelling would be about 40% higher than the estimates shown below.

c. Transpower's indicative pricing for PY22/23 may reflect adjustments to residual charges under the TPM or additional information on gross energy. These are also reflected in the figures for PY22/23. Our inputs and calculations for PY26/27 do not reflect any adjustments events or additional information on demand met from behind-the-meter generation that may have been applied since TPM implementation by Transpower.

d. We have updated the list of designated transmission customers that are customers in PY24/25 and also made the following assumptions:

i. Due to data availability from our sources, we have assumed Manawa Energy and Whareroa Cogeneration Limited's gross energy in PY26/27 is the same as in PY22/23.

ii. We have assumed customers that connected after 2022/23 received no allocation of charges.

iii. We have excluded parties that are no longer transmission customers in 2024/25 (eg, Norske Skog).

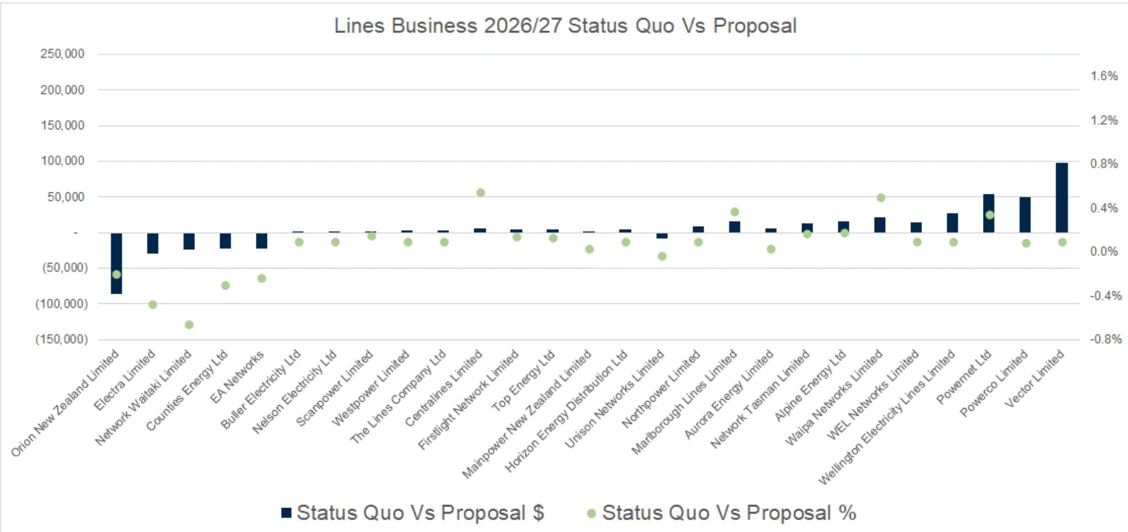
[41] https://static.transpower.co.nz/public/uncontrolled_docs/TPM%20indicative%20pricing%20model%20August%202022.xlsx?VersionId=8Z2mVb4YzAuVELZXz47iIUct39jdGxU0

[42] www.emi.ea.govt.nz/Wholesale/Datasets/Volumes/Reconciliation/

Indicative impact on lines businesses

D.3. The following table and chart show the indicative impact on residual charges in PY2026/27 under the status quo and the proposal for distributors.

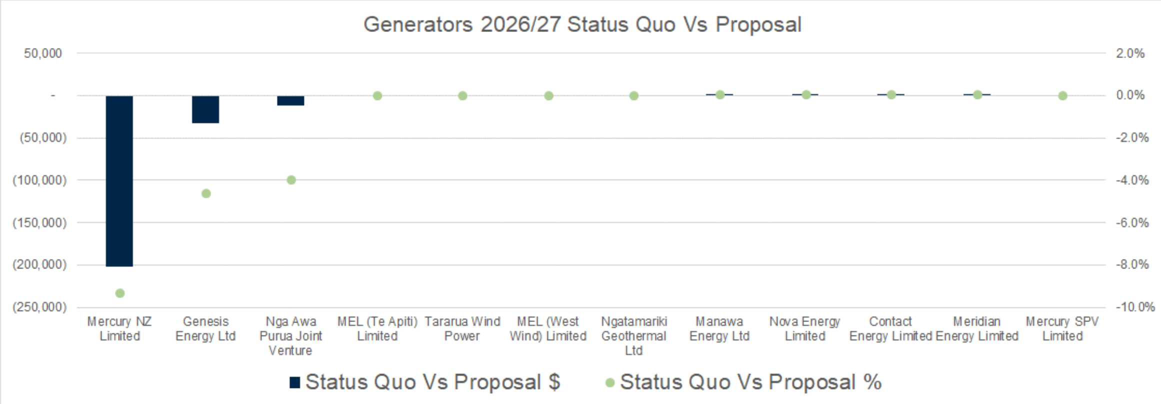
Lines business	2027 Status Quo	2027 Proposal	Status Quo Vs Proposal $	Status Quo Vs Proposal %
Orion New Zealand Limited	42,272,086	42,185,832	(86,254)	-0.2%
Electra Limited	6,257,053	6,227,342	(29,710)	-0.5%
Network Waitaki Limited	3,649,729	3,625,511	(24,218)	-0.7%
Counties Energy Ltd	7,638,590	7,615,704	(22,886)	-0.3%
EA Networks	9,099,704	9,077,771	(21,934)	-0.2%
Buller Electricity Ltd	571,511	572,025	515	0.1%
Nelson Electricity Ltd	743,284	743,954	670	0.1%
Scanpower Limited	831,371	832,594	1,223	0.1%
Westpower Limited	2,808,687	2,811,217	2,530	0.1%
The Lines Company Ltd	4,088,164	4,091,847	3,683	0.1%
Centralines Limited	1,147,575	1,153,798	6,223	0.5%
Firstlight Network Limited	3,350,834	3,355,597	4,762	0.1%
Top Energy Ltd	3,845,141	3,850,062	4,921	0.1%
Mainpower New Zealand Limited	7,488,248	7,490,401	2,154	0.0%
Horizon Energy Distribution Ltd	4,876,859	4,881,252	4,393	0.1%
Unison Networks Limited	20,298,981	20,290,958	(8,022)	0.0%
Northpower Limited	9,551,234	9,559,838	8,604	0.1%
Marlborough Lines Limited	4,125,590	4,140,895	15,305	0.4%
Aurora Energy Limited	17,286,578	17,292,187	5,609	0.0%
Network Tasman Limited	8,172,527	8,186,045	13,517	0.2%
Alpine Energy Ltd	8,824,095	8,839,671	15,576	0.2%
Waipa Networks Limited	4,329,057	4,350,447	21,390	0.5%
WEL Networks Limited	15,645,183	15,659,276	14,093	0.1%
Wellington Electricity Lines Limited	30,467,550	30,494,995	27,445	0.1%
Powernet Ltd	15,910,792	15,964,725	53,933	0.3%
Powerco Limited	57,791,387	57,840,880	49,493	0.1%
Vector Limited	108,302,388	108,399,946	97,558	0.1%
	399,374,199	**399,534,771**	**160,572**	**0.04%**



Indicative impact on generators

D.4. The following table and chart show the indicative impact on residual charges in PY2026/27 under the status quo and the proposal for generators.

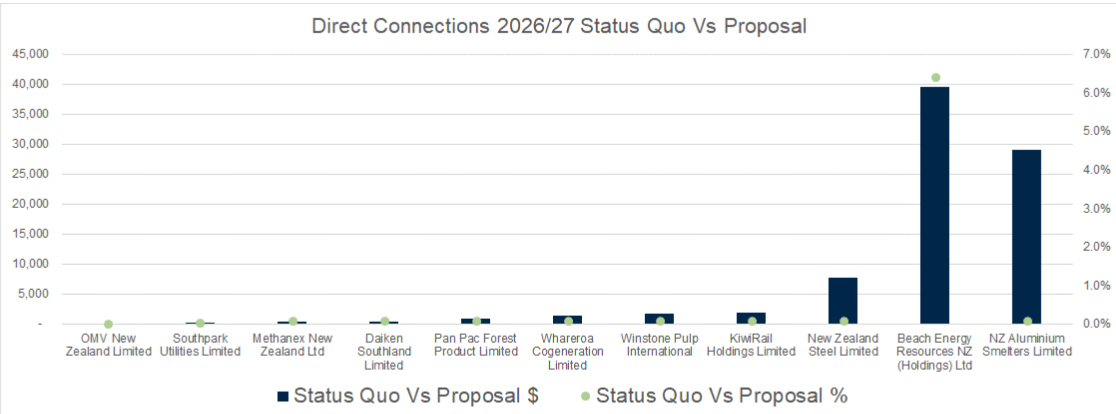
Generator	2027 Status Quo	2027 Proposal	Status Quo Vs Proposal $	Status Quo Vs Proposal %
Mercury NZ Limited	2,165,232	1,963,106	(202,126)	-9.3%
Genesis Energy Ltd	705,391	673,148	(32,242)	-4.6%
Nga Awa Purua Joint Venture	300,122	288,207	(11,914)	-4.0%
MEL (Te Apiti) Limited	-	-	-	
Tararua Wind Power	-	-	-	
MEL (West Wind) Limited	-	-	-	
Ngatamariki Geothermal Ltd	-	-	-	
Manawa Energy Ltd	32,491	32,521	29	0.1%
Nova Energy Limited	334,438	334,739	301	0.1%
Contact Energy Limited	1,250,424	1,251,550	1,126	0.1%
Meridian Energy Limited	1,277,189	1,278,340	1,150	0.1%
Mercury SPV Limited		-		
	6,065,287	**5,821,611**	**(243,675)**	**-4.0%**



Indicative impact on direct connects

D.5. The following table and chart show the indicative impact on residual charges in PY2026/27 under the status quo and the proposal for direct connects.

Direct connects	2027 Status Quo	2027 Proposal	Status Quo Vs Proposal $	Status Quo Vs Proposal %
OMV New Zealand Limited	-	-	-	
Southpark Utilities Limited	9,374	9,378	4	0.0%
Methanex New Zealand Ltd	490,543	490,985	442	0.1%
Daiken Southland Limited	502,753	503,206	453	0.1%
Pan Pac Forest Product Limited	904,853	905,668	815	0.1%
Whareroa Cogeneration Limited	1,583,975	1,585,402	1,427	0.1%
Winstone Pulp International	1,850,163	1,851,830	1,667	0.1%
KiwiRail Holdings Limited	2,077,531	2,079,402	1,871	0.1%
New Zealand Steel Limited	8,612,587	8,620,345	7,758	0.1%
Beach Energy Resources NZ (Holdings) Ltd	617,971	657,604	39,634	6.4%
NZ Aluminium Smelters Limited	32,229,964	32,258,997	29,033	0.1%
	48,879,714	**48,962,817**	**83,103**	**0.2%**



Appendix E Format for submissions

Submitter	

Questions	**Comments**
Q1. Do you agree with the proposed amendment for connection charges for shared connection assets?	
Q2. Will the proposed amendment have any unintended consequences for unusual connection arrangements, eg complex connections?	
Q3. Do you agree with the proposed amendment to the residual charge annual adjustment?	
Q4. The residual charge is intended to be non-distortionary and this proposed amendment is aimed at levelling the playing field and avoiding inefficient investment (irrespective of technology). Are there any other approaches the Authority should consider to address this issue?	
Q5. Do you agree with the objectives of the proposed amendment? If not, why not?	
Q6. Do you agree the benefits of the proposed amendment outweigh its costs?	
Q7. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.	
Q8. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	

Q9. Do you agree with the objectives of the proposed amendment? If not, why not?	
Q10. Do you agree the benefits of the proposed amendment outweigh its costs?	
Q11. Do you agree the proposed amendment is preferable to the other option? If you disagree, please explain your preferred option in terms consistent with the Authority's main statutory objective in section 15 of the Electricity Industry Act 2010.	
Q12. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	
Q13. Do you have any comments on the drafting of the proposed amendment in Appendix A?	
Q14. Do you have any comments on the drafting of the proposed amendment in Appendix B?	