Improving Prudential Security Arrangements

Code change consultation paper

31/03/2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on a proposal to amend the Electricity Industry Participation Code 2010 (Code) in response to concerns raised by retailers about the impact of prudential security arrangements on their ability to operate and grow.

By improving the efficiency of prudential security requirements without increasing risk to the wider market, the proposals are intended to help lower barriers to growth and support a more diverse retail market. Over time, a more vibrant retail environment should provide households and businesses with greater choice and improved value.

Small retailers are most impacted by prudential requirements

In October 2025, the Authority published an issues and options paper which sought feedback on:

- the impact of wholesale market prudential requirements on small retailers' ability to grow and compete in the market, and
- options to make it easier for retailers to meet their obligations without increasing counterparty risk.

We identified two issues with the way that prudential arrangements affect small retailers:

- Small retailers have a greater proportion of their working capital tied up in prudential requirements as they generally meet their requirements using cash deposits, whereas larger retailers are more likely to use financial instruments. This limits small retailers' ability to grow and compete in the retail market and can increase vulnerability in periods of market stress.
- Small retailers cannot offset purchases with large-scale generation and may not have sufficient access to hedging offsets. This exposes them to more volatility in prudential costs, making it more difficult to plan and requiring additional capital to be held as a buffer rather than being put to productive use.

We also noted a related issue for retailers utilising the ASX futures market – because there are separate prudential requirements for the ASX and the physical wholesale market, retailers must post security in two different places, despite their net positions across both markets potentially offsetting.

We sought feedback on four options to improve the efficiency of prudential settings

As of 31 January 2026, there are 27 small retailers which each service 1,000 or fewer ICPs who purchase electricity from the wholesale spot market and incur prudential obligations. These retailers are responsible for less than 1% of total market share but historically have been the most likely to enter into default.

The Authority invited feedback on four options to make it easier for small retailers to meet their prudential obligations.

- Adjusting the 'adder' component of the exit period prudential margin on a dynamic basis (the adder is to account for potential unexpected upswings in wholesale prices).
- Reducing the post-default exit period to 14 days (from the current 18 days) for retailers with 1,000 or fewer ICPs with an equivalent reduction to the Authority's trader default process to offset any increased risk to generators.
- Reallocating residual funds held in the clearing manager's account (these funds accumulate from interest accruing on deferred payments) to retailers on a scaled basis. Residual funds are currently disbursed to generators.

- Enabling ASX hedges to be taken into account in the calculation of prudential requirements.

We modified our proposals based on further analysis and submitters' feedback

We received feedback from 11 submitters on the issues and options paper. Following consideration of submitters' views, the Authority is seeking feedback on two proposed Code amendments to improve the efficiency of the current arrangements.

Reducing the post default exit period by four days for small retailers

The Authority is proposing to reduce the post default exit period by four days for retailers with 1,000 or fewer ICPs. This amounts to a 21% reduction in total exit period exposure for these retailers.

This proposal reflects our confidence that we can execute the trader default process for retailers of this size in a shorter time frame than the current 18 days. We intend that any future expansion of this proposal to larger retailers will also be based on operational feasibility, including improvements to registry software to support switching greater volumes of ICPs during trader defaults.

Reallocating residual funds to retailers

The Authority is proposing to reallocate residual funds to spot market purchasers (including retailers) according to their share of total purchase volumes.

Our earlier proposal to scale the allocation of residual interest towards small independent retailers was based on the view that these payments could provide a modest offset to prudential requirements, given these retailers do not have generation assets which naturally offset their prudential requirements. Further analysis shows that the amount of residual funds ordinarily available for redistribution is significantly smaller than we had previously understood, reducing the scope for meaningful benefit from scaling.

We have also amended this proposal in response to feedback that the settlement and prudential security arrangements should be neutral with respect to the type of business model. Under the revised proposal, residual funds will be allocated proportionately to all purchasers according to their purchase volumes irrespective of business model.

We are no longer progressing work on the other options

The Authority has decided not to progress further work at this time on a dynamic adder due to the risk of increasing volatility in prudential payments. We have also decided not to further investigate enabling ASX hedges to be taken into account in calculating prudential requirements as the costs and complexity appear to outweigh the market's interest. We will however follow developments in Australia where investigating offset arrangements was one of the recommendations of the 2025 National Electricity Market (NEM) review.

This proposal compliments our wider policy initiatives to support retail competition

Alongside this proposal, the Authority is progressing a raft of initiatives to encourage competition and growth in the retail market. These include a new comparison and switching service, evolving retailing arrangements by allowing customers to choose different retailers for consumption and generation, introducing standards for the real-time exchange of consumer data, and requiring half-hourly reconciliation where smart meters are in place.

We welcome your feedback

The Authority welcomes feedback on the proposed Code amendments in this consultation paper. We invite stakeholders to contact us if they would like a briefing during the consultation period.

We will consider all submissions before making a final decision, which we expect to publish in July 2026.

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1 What you need to know to make a submission

What this consultation is about

1.1 The Electricity Authority Te Mana Hiko (Authority) seeks feedback on proposals to amend the Electricity Industry Participation Code 2010 (Code) to make it easier for retailers to meet their wholesale prudential requirements. This paper follows the previous issues and options paper available here: Improving prudential security arrangements: issues and options.

1.2 The paper sets out:

(a) a summary of the submissions we received on the issues and options paper

(b) our preferred approach to improving the prudential arrangements

(c) proposed Code amendments

(d) our assessment of the costs and benefits of the proposal.

How to make a submission

1.3 The Authority's preference is to receive submissions in a Word document in the format shown in Appendix B. Submissions should be in electronic form and emailed to wholesaleconsultation@ea.govt.nz with 'Consultation – improving prudential security arrangements' in the subject line by 5pm 24 April 2026.

1.4 The Authority will confirm receipt of all submissions.

1.5 If you are unable to send your submission electronically, please email wholesaleconsultation@ea.govt.nz or call 04 460 8860 to discuss alternative arrangements.

1.6 We will publish all submissions. If you consider that we should not publish any part of your submission, please:

(a) indicate which part should not be published and explain why,

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

1.7 All submissions, including any parts 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 Act.

2 Background

Relevant aspects of the existing settlement and prudential security arrangements

2.1 Prudential requirements are financial obligations placed on wholesale spot market purchasers to provide security for the electricity they buy from the clearing manager. These requirements help manage counterparty credit risk by ensuring generators (who must sell all electricity to the clearing manager) are paid for all electricity supplied, even though it is consumed before it can be invoiced and paid for.

2.2 The current methodology for determining prudential requirements has two main components:

(a) General outstandings – the net amount (purchases minus generation) a participant accrued in the past month but has not yet paid for and the present month's estimated charges.

(b) Exit period prudential margin – an amount intended to cover the clearing manager's exposure to the retailer for the period of time necessary to exit them from the market following a default.

2.3 The duration of the exit period prudential margin for retailers is 18 days (the post default exit period) plus an additional trading day. This represents the time it would take after a retailer default for the Authority to ensure that other solvent retailers have taken responsibility for the defaulting retailers' customers.

2.4 Risk in the prudential arrangements is managed according to a targeted probability of loss given default (PLGD). This estimates the likelihood that on a given day, the security held by the clearing manager is insufficient to cover a participant's liabilities if they were to default, cannot remedy it and are exited from the market. Current prudential settings target a PLGD of 25%.

2.5 When calculating the exit period prudential margin, the clearing manager uses base prices as well as a fixed 'adder'. The adder is an additional $/MWh amount determined for a full calendar year. For 2026, it is set at $33.76/MWh. The adder is included as a buffer to maintain a PLGD of 25% under the Code.

2.6 Actual settlement of amounts owed to and by the clearing manager occurs on a monthly basis. Each month, some residual credit remains in the clearing manager's settlement accounts due to the accrual of interest on deferred payments. Deferred payments can occur when GST is paid after settlement or if funds are retained in the event of an undesirable trading situation.

Context of this paper

2.7 In October 2025, the Authority released the issues and options paper: Improving prudential security arrangements.[1]

2.8 This work was prompted by an increase in prudential breaches and defaults by small retailers since 2024. We had also heard from some retailers that the prudential framework was constraining their ability to expand their business and compete effectively.

2.9 We identified issues that particularly impact small retailers in complying with their wholesale market prudential requirements and invited feedback on four options for improvement. The aim of these options was to decrease the minimum security required[2] (making it easier for

[1] Improving prudential security arrangements – issues and options paper

[2] Minimum security required is the least of the four daily estimates the clearing manager makes of each participants exposure. Security covering this amount must be provided to the clearing manager at 1600 hours on each business day.

small retailers to meet their prudential requirements) without increasing credit risk in the wholesale electricity market.

2.10 The four options for improvement were:

(a) Adjusting the adder component of the exit period prudential margin on a more dynamic basis.

(b) Reducing the duration of the post-default exit period by four days for retailers servicing 1,000 ICPs or fewer (with an equivalent reduction to the Authority's trader default process).

(c) Reallocating the interest accrued on residual funds to retailers rather than generators on a scaled basis.

(d) Investigating offsetting the general prudential requirement with the clearing manager by accounting for ASX futures positions.

2.11 The consultation period closed on 28 November 2025. The feedback we received has informed the development of this paper.

3 Feedback from submissions and Authority response

We received 11 submissions from a range of stakeholders

3.1 Eleven stakeholders provided feedback on the Improving prudential security requirements: issues and options paper. The submitters were:

Table 1: Issues and options paper submitters

	Submitter	Type of submitter
1	Contact Energy	Generator-retailers
2	Meridian Energy	
3	Lodestone Energy	
4	Nova Energy	
5	Electricity Retailers' and Generators Association of New Zealand (ERGANZ)	Industry association
6	Haast Energy Trading	Independent trading business
7	emhTrade Markets	
8	Octopus Energy	Independent retailers
9	Electric Kiwi	
10	For Our Good	
11	Paua to the People	

3.2 Each submission has been published in full on the Authority's website.[3]

3.3 The following sections discuss this feedback and our response across three areas:

(a) the Authority's approach to maintaining the risk profile of the prudential requirements and the impact of the requirements on small retailers

(b) the options proposed for improving prudential requirements for small retailers

(c) additional suggested options.

[3] Improving prudential security arrangements | Our consultations | Our projects | Electricity Authority

Our approach to risk and issues in the prudential arrangements

3.4 In the issues and options paper, we considered that the current risk profile of the prudential framework (ie, a targeted PLGD of 25%) was sufficient and should be maintained. We did not explore options that would alter or redistribute the existing credit risk parameters.

3.5 However, our analysis did highlight several areas where the requirements could create difficulties for small retailers. These included:

(a) Small retailers often have a high proportion of their working capital tied up in prudential security.[4] This may limit their ability to grow and compete in the retail market and increase their vulnerability to default in periods of market stress.

(b) Small retailers experience greater volatility in the cost of prudential requirements.[5] This may make it more difficult to plan and manage cash flow, potentially requiring additional capital to be held as a buffer rather than put to productive use.

Most submitters were in favour of maintaining the current risk profile of the prudential arrangements

3.6 The majority of submitters were comfortable with the overall risk target of the prudential framework and, collectively, their responses indicated a view that the current settings provide generators with adequate protection against retailer defaults. Meridian Energy explicitly opposed any prospect of increasing PLGD noting that the current standard is already more tolerant than comparable jurisdictions.

3.7 Most submitters also agreed that any approach for future improvement should concentrate on refinements that improve the efficiency of the settings, so that prudential costs on retailers are proportional to the risks they pose to the market. Lodestone Energy noted that the framework should be capable of recognising the distinction in risk between, for instance, a retailer with reliable cash-flow that can demonstrably cover its position and another with weaker cash-flow or a poorly matched hedge stack.

3.8 Paua to the People and For Our Good expressed a view that changes to the current risk profile were warranted. The former argued that retailers bear the full risk of non-payment from consumers, stressing that collection has become more challenging amid rising electricity and living costs. The latter considered that the current balance is arbitrary and that the unique margins or business models of small social purpose retailers could justify a different tiered PLGD.

3.9 All submitters signalled support for, or were neutral to, the Authority addressing the identified issues in principle. ERGANZ did however note that in the context of the broader and more complex work the Authority is currently undertaking, the priority for these proposals should be low.

Our response

3.10 The Authority believes that the features of the prudential arrangements impacting small retailers should be addressed, if possible, by improving the efficiency of prudential settings while keeping the existing risk profile unchanged. This is based on the current target being more risk-tolerant than that of similar international regimes, as well as the continued support for the target from both generators and retailers.

[4] This is because smaller retailers are more likely to use cash as security whereas larger retailers are more likely to use financial instruments such as bank guarantees or letters of credit as security.

[5] This is because smaller retailers are usually independent and therefore do not have generation to offset their purchasing, or because they may have less access to hedges capable of offsetting their prudential costs.

3.11 We agree with Haast Energy Trading that the core purpose of the prudential regime is to effectively manage counter-party credit risk. In our view, this is best achieved by requiring those who create the risk (traders, by consuming electricity before it can be paid for) to provide collateral that covers the exposure they create for the wider market.

3.12 In most ordinary markets, the seller of a commodity can decide whether to transact with a buyer based on its perception or understanding of that buyer's creditworthiness. In the New Zealand wholesale electricity market, generators do not have this option because all electricity must be first sold to the clearing manager. As a result, the clearing manager must assume responsibility for managing counter-party credit risk, and it must fall on the end purchaser to secure its position.

3.13 We also consider it important that the framework incentivise the prudent management of risk by individual traders. One way this can be achieved is by providing participants who enter contracts that reduce their risk with the ability to offset their security requirements. Ultimately, our objective is to ensure that each retailers' prudential costs reflect, as closely as possible, the level to which they expose the wider market to risk.

3.14 We acknowledge the value that social purpose retailers provide to consumers and recognise that their business models may differ from industry norms (such as through more frequent billing cycles or different margins). However, we do not consider that these features give rise to a principled justification for an alternative tier of risk tolerance. These features do not necessarily reduce credit risk in the market, and we are of the view that credit risk should be managed uniformly across participants.

3.15 We agree that, in general, retailers assume all of the risk of non-payment by their customers. However, we consider this appropriate. Retailers, by nature, are the market participants most closely connected to end consumers (excluding directly connected industrials). When a consumer fails to pay, it is the retailer – rather than the clearing manager or the generator – that has both the exposure and the means to pursue recovery. As such, the allocation of this risk reflects their position in the value chain and the practical avenues for redress.

3.16 Ultimately, we propose maintaining the current risk profile of the system and applying the risk profile uniformly across participants (ie, each participant's security is calculated according to the same PLGD target). The improvements we propose are intended to achieve this while creating efficiency gains and cost savings for small retailers to enable them to grow and better compete.

We proposed transitioning to a dynamic adder

3.17 In the issues and options paper, we proposed introducing more flexibility into the adder component of the exit period prudential margin. We suggested this could be achieved by recalibrating the value on a seasonal or quarterly basis with the expectation that doing so would reduce instances of the clearing manager procuring excess security, thereby reducing costs for retailers.

3.18 Other than suggesting that a dynamic adder could be tailored to historical volatility patterns (if updated seasonally) or to peak demand volatility (if updated by trading period intra-day), we did not elaborate on specific design options.

The majority of submitters supported moving to a more dynamic adder

3.19 Five submitters (ERGANZ, For Our Good, Lodestone Energy, Meridian Energy and Octopus Energy) supported transitioning to a more dynamic adder. Most did so on the basis that a dynamic adder would better align exposure estimates with underlying conditions of the

wholesale market such as seasonal shifts in price volatility, with the possibility of reducing the likelihood of over-collateralisation in stable periods.

3.20 For Our Good commented that adjusting the adder amount seasonally makes sense insofar as it is done on a clear and predictable basis such that retailers have time to plan ahead. Lodestone Energy also noted the method should be published and updated on a quarterly basis so that retailers are well positioned to forecast their particular cash needs.

3.21 Contact Energy raised some concern that the benefits of a more dynamic adder were only assessed for retail participants but considered that accurate implementation would also benefit generators. However, they considered that any assessment of whether a dynamic is needed should be left to the clearing manager.

3.22 Paua to the People and Electric Kiwi opposed the transition to a dynamic adder, arguing that it would create greater unpredictability and exacerbate capital management issues. Paua to the People noted specifically that it requires relief in those periods were market volatility is highest – a dynamic adder would only offer relief in periods of relative stability. Electric Kiwi stated that it would still need to continue forecasting for the highest possible prudential amounts regardless.

Our response

3.23 Having considered submitters' feedback and conducted further analysis, we have decided not to progress with the proposal to transition to a dynamic adder.

3.24 The choice between dynamic and static calculation of the adder reflects a trade-off between accuracy and predictability. A dynamic adder would more closely align prudential estimates with actual exposure, creating the potential for cost savings in stable periods. However, it would also introduce additional variability that retailers would need to account for in their cash-flow planning. By contrast, the current static approach avoids this variability. It provides a fixed amount that is set annually and published two months in advance, offering retailers a higher degree of certainty.

3.25 To help assess the potential value of a dynamic adder, we also asked the clearing manager to model the potential cost savings. The model compared changes in exit-period spot purchases, spot sales, and hedge amounts between current settings and a scenario where the adder is removed entirely. This approach allowed us to capture the maximum theoretical scope of any savings associated with dynamic adjustment.

3.26 The results showed that without an adder, exit-period spot sales and purchases decreased consistently by 20–24%. However, the effect on exit-period hedge exposures varied widely across participants and displayed no stable or predictable pattern. Percentage differences ranged from −231% to 307%, indicating that hedge positions are extremely sensitive to exit-period price movements.

3.27 This highly variable interplay between hedge exposures and the removal of the adder raises concerns. It suggests that even a partially dynamic adder could unintentionally amplify prudential volatility in ways that are difficult to anticipate or manage. The Authority wants prudential requirements to encourage effective risk management. A dynamic adder that distorts hedge behaviour in this way runs counter to that purpose.

3.28 It is also important to note that the modelled scenario (complete removal of the adder) overstates the impact that a real-world dynamic adder would have. In practice, any dynamic approach would still apply a non-zero adder for prudential purposes, meaning that the actual reductions in spot or hedge positions would be materially smaller than the modelled percentages.

3.29 This impact would be further reduced if, as suggested by Electric Kiwi and Paua to the People, retailers continued to retain any excess cash generated by a lower adder during stable periods in anticipation of higher prudential requirements during periods of volatility. If this persisted, the practical efficiency gains would be further limited.

3.30 We agree with the majority of submitters that a more dynamic adder would better align prudential coverage with actual exposure, potentially delivering cost savings in stable periods. However, we consider that the practical value of these savings (especially for small retailers) is likely to be limited. Therefore, we are not proceeding with this proposal.

We proposed reducing retailers' post default exit period by four days

3.31 In the issues and options paper, we proposed reducing the post default exit period by four days for retailers with 1,000 ICPs or fewer. This would reduce the period for which the exit period prudential margin is calculated, decreasing the amount of security required year-round and providing meaningful cost savings for retailers.

3.32 However, if a retailer default were to occur under these circumstances, and the ordinary 18-day trader default process was used to exit the retailer, the defaulting retailer's prudential security would be insufficient to cover the last four days of exposure. This would create additional credit risk to generators. Therefore, we also proposed streamlining the trader default process such that the Authority could exit a defaulting retailer and provide for the switching of its customers to solvent retailers within the shorter timeframe. We proposed that this could be achieved by reducing phase 2 of the trader default process by one day and phase 3 by three days.

3.33 Currently, phase 2 of the trader default process runs from Day 8 to Day 14. On Day 8, the Authority publicly announces that the retailer has defaulted and customers are urged to switch to an alternative retailer during the remainder of the phase. Phase 3 of the trader default process runs from Day 15 to Day 18. During this phase, the Authority provides for the mandatory assignment of any remaining customers to solvent retailers.

3.34 The 1,000 ICP threshold was included as the Authority is confident that it can execute the trader default process in a reduced timeframe for retailers of this size. We also signalled that we were open to extending the reduction in the post-default exit period to independent retailers (retailers that focus on operating in the retail market, unlike the vertically integrated 'generator-retailers') with over 1,000 ICPs, noting that improvements to registry software are needed first to support switching greater volumes of ICPs during trader defaults.

Submitters generally supported post-default exit period reductions

3.35 In principle, all submitters (with the exclusion of Haast Energy Trading who did not comment on the option specifically) supported reducing the post-default exit period with a commensurate reduction in the Authority's trader default process. Most considered the proposal would provide helpful financial relief (especially for small retailers), freeing up capital for growth and innovation.

3.36 There were, however, a range of differing views as to the particular design and application of the proposal.

3.37 Commentary on the design of the proposal included:

(a) Support for the permanent removal of the three-day tender process in Phase 3 of the trader default process on the basis that the Authority is unlikely to ever utilise it when executing a trader default (Octopus Energy, Meridian Energy, and most other submitters by implication).

(b) Caution against the reduction of Phase 2 of the trader default process by one day on the basis that doing so would impose additional time pressure on customers seeking an alternative retailer following notification that their retailer has defaulted and because the value of the additional day's reduction is unlikely to outweigh the increased disruption (Meridian Energy).

3.38 Commentary on the qualifying threshold of the proposal included:

(a) Support for initially limiting the proposal to retailers servicing 1,000 ICPs or fewer, prior to the completion of operational adjustments that could justify increasing the qualifying threshold (Octopus Energy, Contact Energy, ERGANZ, Lodestone Energy, and Meridian Energy).

(b) Support for expanding the qualifying threshold to all independent retailers once operational adjustments allow (Octopus Energy, Electric Kiwi, For Our Good and Lodestone Energy).

(c) Caution against limiting reductions in the post default exit period to independent retailers on the basis of their business model but support for application of the proposal on the basis of feasibility (such as linking the proposal to ICP volume, speed of customer transfer, operational constraint on the clearing manager or the risk of non-payment generally) (ERGANZ and Meridian Energy).

(d) Caution against limiting reductions in the post default exit period to independent retailers on the basis of their business model but support for universally reducing the post-default exit period for all retailers (Contact Energy).

3.39 Contact Energy also emphasised that although generator-retailers (or large retailers) predominantly meet their required security in the form of financial instruments, these also have an associated financing cost – with some remainder usually being met in the form of cash. They also argued that any exclusion on the basis of ability to pay is unprincipled.

3.40 Electric Kiwi and For Our Good also suggested that the effect of simply limiting the application of the proposal to retailers with 1,000 ICPs or fewer would be immaterial in terms of creating a measurable impact on market competition, investment or innovation.

Our response

3.41 Based on our assessment of submitters' feedback and further analysis, our preference is to proceed with reducing the post-default exit period by four days for retailers with 1,000 ICPs or fewer.

Shortening the duration of the trader default process

3.42 The Authority proposes a four-day reduction in the trader default process in the manner described in the issues and options paper (ie, a one-day reduction to phase 2 and a three-day reduction to phase 3). We recognise that all submitters who commented specifically on the proposal favoured reducing phase 3 by removing the option for the Authority to run a competitive tender process for the allocation of a defaulting traders' customers.

3.43 In response to Contact Energy's concern about shortening Phase 2 of the trader default process by one day, we acknowledge that moving to a six-day window may increase time pressure for some customers seeking an alternative retailer, particularly commercial and industrial customers with more complex requirements.

3.44 We also recognise that, following a default, some commercial customers may be unable to secure a contract with a new retailer on terms comparable to their previous arrangements. In some cases, achieving this may not be possible at all if no retailer is willing to offer similar

terms. The Authority intends to further consider issues affecting commercial customers as part of a future review of the trader default guidelines. In relation to this consultation, however, it is unlikely that reducing Phase 2 by one day will materially affect the position of customers attempting to negotiate a new contract with an alternative retailer.

We propose initially limiting the exit-period reduction to retailers with 1,000 ICPs or fewer

3.45 We propose initially limiting the reduction in the post-default exit period to retailers with 1,000 ICPs or fewer. This reflects the stated policy goal of making it easier for small retailers to meet their prudential obligations and our assessment that, all else being equal, the Authority can operationally manage the switching of customers (including commercial and industrial customers) within a reduced timeframe following the default of a retailer of this size.

3.46 Our previous paper signalled that the Authority was interested in reducing the default exit period for all independent retailers. This was on the basis that many independent retailers are relatively small and therefore more impacted by prudential requirements. However, having considered submitters' feedback, the Authority intends that any future extension will depend on the Authority's confidence that it can execute the trader default process for retailers of different sizes. As improvements to automation and switching capability are implemented, the qualifying threshold for a reduced post-default exit period can then be extended to those retailers for whom a shorter post-default exit period is operationally feasible.

3.47 Our analysis indicates that if a reduced post default exit period were in place for the October-November prudential period, retailers with 1,000 ICPs or fewer would have had to provide a combined $124,285 less in security than under the current arrangements. This figure would be larger in winter periods when exit period prices are typically more elevated.

3.48 If a retailer previously responsible for servicing 1,000 ICPs or fewer becomes aware that it is or will be responsible for servicing more than 1,000 ICPs, it must immediately inform the clearing manager in order that the clearing manager adjust the retailer's post-default exit period accordingly. A retailer responsible for servicing 1,000 ICPs or fewer may also increase its post default exit period to no more than 18 trading days by giving 20 business days' notice to the clearing manager.

We proposed a scaled reallocation of residual funds to small retailers

3.49 In the issues and options paper, we proposed disbursing residual funds and interest to retailers instead of generators. While these funds had previously been allocated to generators to compensate for excess credit risk, we considered it more appropriate to allocate them to retailers because the funds primarily originate from spot purchasers' payments and because losses to generators following defaults have been scarce and nominal.

3.50 We further suggested weighting the distribution towards independent retailers, many of which are small. The model we proposed for this was allocating half of the total monthly residual funds to all spot market purchasers by percentage of total purchase volumes and half to all independent retailers by relative percentage of total purchase volumes.

Submitters had conflicting views on residual funds reallocation

3.51 Support for this option was mixed:

(a) All independent retailers and Lodestone were in favour of reallocating residual funds (or a portion thereof) to retailers on a scaled basis, although Paua to the People questioned

the extent of its potential benefits (Octopus Energy, Electric Kiwi, For Our Good and Loadstone and Paua to the People)

(b) All major generator-retailers and ERGANZ opposed reallocating residual funds on a scaled basis (Contact Energy, ERGANZ and Meridian Energy).

3.52 Consistent with the theme of their responses to the previous option, Contact Energy, ERGANZ and Meridian Energy voiced strong concerns about the prospect of justifying residual funds allocations on the basis of business model, stating:

"…we are deeply concerned by the proposals to have arbitrary differences in treatment for smaller and larger retailers. Of most concern is the proposal to bias the return of residual funds to smaller retailers. This is a direct value transfer that sets a dangerous precedent for larger market participants directly subsiding smaller ones. This would materially harm the efficient operation of the market." – Contact Energy

"…these approaches seek to advantage one business model over another without clear justification or principled reasoning. We consider that prudential arrangements should be solely focussed on ensuring the efficient management of the risk of non-payment in the wholesale market. They should not be a means to advantage one business model over another or to seek to alter the dynamics of retail market competition." – Meridian Energy

3.53 Contact Energy, Meridian Energy, and ERGANZ noted, however, that a reasonable argument could be made for allocating residual funds interest to spot market purchasers, given that these funds largely represent money provided by those parties—provided the allocation is based solely on total purchase volumes.

3.54 While all other submitters supported scaled reallocations, they suggested alternative methods for doing so. These included:

(a) allocating all residual funds exclusively to independent retailers (Electric Kiwi)

(b) allocating all residual funds exclusively to independent retailers by the dollar value of prudential security lodged (Octopus Energy)

(c) allocating 70% of residual funds to all purchasers and 30% evenly amongst independent retailers with less than 10,000 customers (For Our Good)

(d) a shared split between generators and retailers with tiered allocations based on their share of purchases, a portion for independent retailers to support competition and a small portion based on strong prudential behaviour (Lodestone Energy).

Our response

3.55 Based on feedback from submissions and further analysis, the Authority proposes to reallocate residual funds to all spot market purchasers in proportion to their purchase volumes.

3.56 In the issues and options paper, we noted that $2.94 million in residual funds had been distributed to generators between June 2024 and April 2025. Further analysis has shown, however, that this figure overstates the level of residual funds ordinarily available for distribution. This is because a significant proportion of the disbursements during that period comprised funds accumulated following the 9 August 2021 UTS, rather than residuals generated through normal operations.

3.57 For example, in February 2025, $1.97 million in gross residual funds were allocated to participants (an amount heavily influenced by the release of UTS-related balances). By comparison, monthly residual allocations over March–December 2025 ranged from $6,785 to $61,768, demonstrating that typical operational residuals are substantially lower.

3.58 Given that typical monthly residual allocations are likely to be more modest, the Authority no longer considers it necessary or proportionate to apply a more complex scaling mechanism to their distribution. However, we still consider it appropriate that residual funds be allocated to purchasers (rather than generators) because these funds largely arise from interest accrued on funds originally provided by purchasers. Allocating residual funds in proportion to total purchase volumes provides a simple and transparent approach, maintains neutrality across business models, and avoids the targeted redistribution effects that many submitters opposed. Had the proposal been in effect for the March to December 2025 residual funds allocations, $72,063 would have been credited to purchasers, including independent retailers. Of this, $695 would have been returned to retailers with 1000 or fewer ICPs.

We proposed developing a physical and futures offsetting arrangement

3.59 The issues and options paper canvassed the impact of separate margin and prudential arrangements for the wholesale spot market and the ASX futures markets. Retailers who utilise both markets to manage risk must post collateral twice (ie, with both the clearing manager and their ASX clearing participant), despite net positions potentially offsetting across the two markets.

3.60 In the physical wholesale market, participants who have entered into over-the-counter (OTC) bilateral hedge agreements can register these with the clearing manager in the form of a Hedge Settlement Agreement (HSA). When an HSA is lodged, the clearing manager will settle the contract on behalf of the parties, allowing for its strike price to be reflected in prudential calculations. No such mechanism exists for ASX futures contracts.

3.61 We sought feedback on interest in the development of a possible ‘physical and futures offsetting mechanism’. We suggested that one vehicle for achieving this could be deployment of the daily trading data the Authority now receives from ASX with the clearing manager (on an opt in basis).

Feedback varied on the utility of a physical and futures offsetting arrangement

3.62 Most submitters (Contact Energy, ERGANZ, For Our Good, Lodestone Energy, Meridian Energy, Paua to the People, and Octopus Energy) supported the proposal to provide for offsetting of prudential requirements between the spot market and the ASX futures market in principle but raised varying degrees of scepticism.

3.63 The strongest proponents argued that all forms of financial cover should be capable of offsetting prudential requirements. They suggested that recognising ASX futures contracts for this purpose could have the additional benefit of increasing liquidity and improving price discovery in the futures market. Lodestone Energy argued that treating verified exchange positions as prudential offsets could reduce cash-drag, broaden participation and better align prudentials with net risk.

3.64 ERGANZ and Octopus Energy both commented that potential functional workarounds we identified are possible at present but are either imperfect or insufficient.

3.65 Contact Energy and Meridian Energy supported further exploring the proposal in principle but emphasised the need for a high degree of certainty around the scale of the benefits, costs and implementation timeframes. They also stressed that confidence in the effective operation of any mechanism is essential before adoption. Contact was particularly concerned about the need for robust processes to ensure that retailers’ offsetting effects are accurately and continuously reflected in their actual ASX positions, noting the risk that retailers could temporarily hold offsetting positions to reduce prudential requirements and then quickly unwind them, exposing the clearing manager to unsecured risk.

3.66 Electric Kiwi considered that a physical and futures offsetting arrangement is "unlikely to materially impact most retailers or meaningfully enhance competition or reduce cost pressures in the current environment." They observed that ASX risk-management contracts are "prohibitively expensive for most retailers", resulting in limited uptake across the industry. Instead, they expressed support for recent improvements to HSAs[6] and recommended further work in this area as a more effective way to help retailers manage prudential costs.

3.67 EmhTrade was strongly opposed to this option on the basis that it would involve the sharing of deanonymized trading data with third parties and because it would be difficult (despite trading data) for the clearing manager to reliably know a participants ASX position or gain priority to ASX funds in the event of a default.

Our response

3.68 While we see potential scope for benefit from a physical and futures offsetting arrangement, we have decided not to progress this proposal at this stage. The primary reasons for this include:

(a) The complexity, risks and costs associated with the proposal appear to be greater than the appetite and interest of the market in such a mechanism (assuming that submissions reflect general market sentiment).

(b) We did not receive sufficient evidence or reasoning to suggest that the scale of any benefits is likely to be greater than when the Authority previously considered the matter in 2018.[7]

(c) Small retailers currently purchase relatively few ASX derivative contracts and the volumes they do purchase are modest. We did not receive strong evidence that a physical and futures offsetting arrangement would materially increase ASX participation – either for small or large retailers.

(d) Many over the counter (OTC) contracts are already capable of offsetting prudential requirements if lodged as a hedge settlement agreement (HSA) with the clearing manager. We agree with Electric Kiwi that broadening the suite of contracts capable of supporting an HSA, or otherwise improving HSA functionality is likely to provide greater utility for retailers at present.

3.69 Improvements to the range of OTC contracts capable of supporting HSAs have recently taken effect. We will be monitoring the uptake and impact of these changes and considering whether further broadening HSA functionality is appropriate. In doing so, we will consider the Australian experience in implementing recommendation 8 of its review of wholesale market settings in the National Electricity Market (NEM). [8] This recommended that Australian Energy Ministers commission a review of counterparty credit risk management and prudential arrangements in the NEM, supported by a multi-agency taskforce and industry subject matter experts.

3.70 The NEM wholesale market settings review identified a range of issues similar to those outlined in our issues and options paper. Of particular relevance was reference to inefficient duplication in working capital required as credit support due to separate credit support (prudential) required and an absence of exposure netting between the Australian Energy Market Operator (AEMO), ASX Clear (Futures) and OTC counterparties. It also noted that

[6] On 1 January 2026, Code amendments took effect to allowing the clearing manager to settle fixed price variable volume (FPVV) hedge settlement agreements.

[7] In 2018, the Authority decided against integrating the clearing and settlement for exchange traded derivatives and other wholesale market transactions cleared and settled by the clearing manager. View the decision here: Treatment of prudential offsets in the wholesale market.

[8] See: National Energy Market wholesale market settings review and NEM Review: Supplementary Materials.

the effect of the issue can be exacerbated in periods of volatility. Specific consideration of futures position offsetting within the Australian market will likely provide useful insights for any future development of a similar mechanism in New Zealand.

We sought additional options

3.71 We asked whether there were additional or alternative adjustments (outside of the four main proposals) the Authority could make to better reduce cost or enhance the efficiency of the prudential settings without increasing credit risk.

Submitters identified a range of additional options

3.72 Five submitters highlighted 11 additional or alternative options for the Authority to consider. These ranged from minor process adjustments to significant methodological reviews.

3.73 The additional options are summarised in the table below.

Table 2: Additional options suggested by submitters

	Proposal	Submitter
1	The Authority should remove GST as an input in the prudential methodology.	Electric Kiwi
2	The Authority should explore whether frequent or real-time adjustment of the general prudential requirement (not just the 'adder' component) would better align security with actual exposure.	ERGANZ
3	The Authority should undertake a broader review of prudential requirements including the methodology for determining exposure under financial transmission rights (FTRs) and HSAs, as well as the roll of the clearing manager more generally.	Haast
4	The Authority should recognise all offsets from fixed price variable volume power purchase agreements.	Lodestone
5	The Authority should provide for automatic early warning notices when coverage is nearing thresholds.	
6	The Authority should provide for same day substitution between forms of security (eg, cash and bank guarantees).	
7	The Authority should standardise bank guarantee wording and fee bands with major banks.	
8	The Authority should provide for daily crediting of interest that has accrued on security.	
9	The Authority should provide for simple forecast tools and twice-daily coverage statements.	
10	The Authority should prohibit distributors from imposing prudential security requirements in their use of system agreements with retailers.	Paua to the People
11	The Authority should shift the funding of the customer compensation scheme from retailers to generators.	

Our response

3.74 We thank submitters for their suggestions on additional actions the Authority could take to improve prudential requirements. The following sections set out the Authority's current views on each of these.

Removing GST as an input in the prudential methodology

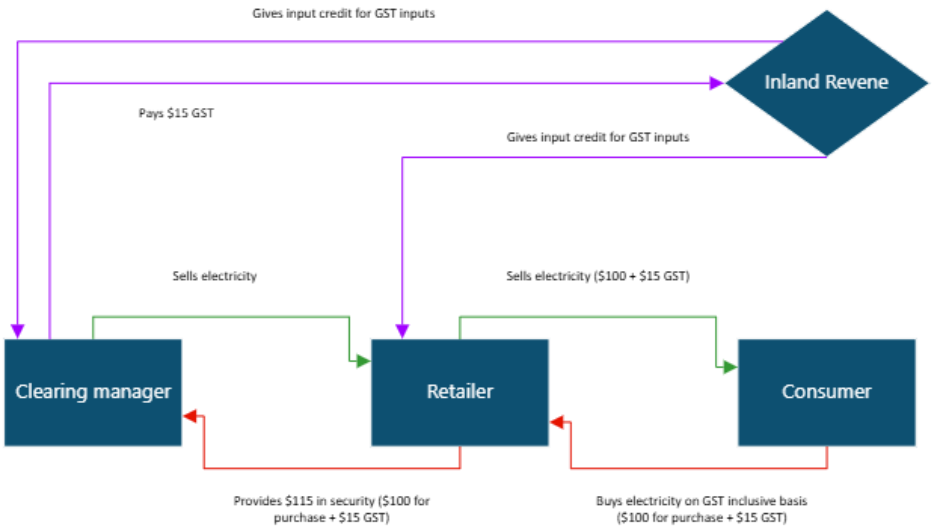
3.75 Electric Kiwi considered that the removal of the requirement to pay GST from the prudential calculation would constitute the single most effective means of reducing prudential costs for independent retailers. At this stage however, the Authority is not able to find a way to do this without increasing credit risk to the clearing manager, or the Crown.

3.76 Electric Kiwi said that a cash-flow timing loss occurs by virtue of the inclusion of GST on spot purchases in prudential estimates despite hedges being zero-rated for GST – the effect being that HSAs are incapable of totally offsetting spot price volatility. They argued that if GST was removed from the prudential estimates, in the event of a default, the GST shortfall would be recoverable from the IRD.

3.77 In considering this issue, we engaged with Inland Revenue. Our current view, informed by those discussions, is that if GST were excluded from prudential payments and a retailer subsequently defaulted (after accounting for any amounts recoverable from Inland Revenue) the total funds available would still be insufficient to cover the clearing manager's exposure. This would result in a loss both to the IRD and passed through to generators.

3.78 The diagram below illustrates a simplified payment flows for GST and prudential security resulting from the purchase of $100 worth of electricity.

Figure 1: GST on electricity purchases (current position)



3.79 Under the current settings, for a $100 electricity purchase from the clearing manager, a retailer must provide $115 in security to account for GST. In a default scenario, the clearing manager can call on the full $115 (paying $15 to Inland Revenue) and thereby settling the debt without needing to recover any additional GST.

3.80 The table below shows the effect on this of removing GST from the prudential calculation.

Table 3: Example effect of removal of GST from prudential calculation

GST Included in prudential	GST removed from prudential
Security provided = $115	Security provided = $100
Clearing manager can call on $115	Clearing manager can call on $100
Clearing manager pays Inland Revenue $15 retaining $100 as security	The $15 component of the invoice for supply of the electricity is not paid. The clearing manager has received $100 (in security) for the supply of electricity. It therefore has to pay GST to Inland Revenue of $13.04 (3/23 * $100).
In a default, no bad debt reduction is ordinarily required and the clearing manager is made whole.	The clearing manager can claim a bad debt deduction for the $15 it has not received, if the debt

	truly is bad, but this only creates a GST adjustment of $1.96 (3/23 * $15). As a result, the clearing manager would face an unsecured exposure of $13.04, and the Crown would incur a $1.96 loss due to the limited GST bad-debt adjustment.

3.81 Based on this initial analysis, we have decided not to progress this proposal as it has the potential to increase the PLGD and counterparty credit risk in prudential arrangements.

Our views on more frequent adjustment of exit period base prices

3.82 Both Nova and Lodestone suggested the Authority consider moving to more dynamic or closer to real time adjustment of exit period base prices (as opposed to or as well as more dynamic adjustment of the adder).

3.83 At this stage, the Authority is not considering progressing this option. The variable interplay between exit period prices and participants hedge positions discussed above in relation to dynamic adjustment of the adder at paragraphs 3.26 and 3.27 is also likely to be present if exit period base prices are adjusted more frequently. This has the potential to distort hedge behaviour without providing for a predictable benefit.

Our views on a broader review of the prudential framework

3.84 Haast Energy Trading considered that the Authority should undertake a broader review of the prudential framework with a wider scope including the role of the clearing manager, HSAs and the FTR prudential methodology.

3.85 The Authority agrees that a broader review could offer opportunities for enhancement that would benefit market participants and consumers. We also agree that the purpose of the prudential regime, including these wider elements, should be to efficiently manage counter party credit risk and enable a low friction risk management market.

3.86 We will consider the potential benefits of any wider review against competing priorities and initiatives in the Authority's work program to strengthen the wholesale market.

Our views on Lodestone's suggested process improvements

3.87 Lodestone raised a number of "low friction process improvements" (described in the table above) for the Authority to consider.

3.88 We see potential merit in many of these, especially those aimed at increasing retailers' visibility of prudential risk (ie, through early warning notices when coverage is nearing exposure thresholds) and those that increase the efficiency of payments made to and from the clearing manager.

3.89 We have shared these suggestions with the clearing manager for its consideration. Ultimately, we are of the view that most of the suggestions (if pursued) are best led by the clearing manager itself. We encourage Lodestone to engage directly with the clearing manager on these matters.

3.90 Lodestone also noted that the Authority should further strengthen the offsetting capability of fixed price variable volume (FPVV) hedge settlement agreements (HSAs). On 1 January 2026, FPVV HSAs were introduced as a new form of hedge settlement available to participants. The strengthening of HSAs is an area of interest for the Authority and we will consider improvements in this area as a part of future work on hedging and risk management.

Our views on distributor prudential and the customer compensation scheme

3.91 Paua to the People made two suggestions:

(a) prohibiting distributors from requiring prudential security from retailers under their use of system agreements

(b) having generators fund the customer compensation scheme rather than retailers.

3.92 At this stage, the Authority is not considering progressing either of these proposals as both fall outside of the scope of this consultation.

3.93 Under the Code, distributors are entitled to include terms for prudential security requirements in their use of system agreements with retailers. These terms must specify that they be complied with by maintaining an acceptable credit rating or by providing acceptable security. The amount of acceptable security must be the distributors reasonable estimate of the distribution services charged that the retailer will be required to pay in any period no longer than two weeks.

3.94 Given that the scope of this consultation is confined to prudential security for retailers' financial obligations to the clearing manager, we are not presently considering amendments to the rules governing distributors.

3.95 The customer compensation scheme is an obligation on retailers requiring them to pay qualifying customers when asked to conserve electricity. The minimum weekly amount is $12.00 per week. The Authority determines the minimum weekly payment and reviews it every three years.

3.96 Likewise, as this consultation is focussed on retailer's prudential obligations to the clearing manager, we are not presently considering amendments to the rules concerning the customer compensation scheme.

Q1. Do you have any comment on the Authority's response to submissions?

4 Our revised proposal

4.1 Based on our assessment of submitters' feedback and further analysis of the potential costs and benefits (discussed in more detail below) our preference is to:

(a) not proceed with the proposal to transition to a dynamic adder

(b) proceed with a four-day reduction in the post-default exit period for retailers with 1,000 ICPs or fewer with a commensurate reduction in the trader default process for these retailers (by reducing phase 2 of the trader default process by one day and phase 3 by three days)

(c) proceed with the proposal to return residual funds and interest to spot market purchasers (without scaling the allocations)

(d) not proceed with the proposal to develop a physical and futures offsetting mechanism.

5 Regulatory impact statement

Objectives of the proposed amendments

5.1 The primary objective of the proposed amendments is to make it easier for small retailers to meet prudential requirements without increasing credit risk to the wider system.

5.2 We want to ensure that prudential requirements are efficient, proportionate to the risks they manage, and do not unnecessarily restrict the ability of small retailers to grow and compete in the market.

Q2. Do you agree with the objective of the Code amendment proposal? If not, why not?

Costs and benefits

Scope of the cost benefit analysis

5.3 We have undertaken an assessment of costs and benefits that includes quantitative analysis of costs and retailer level benefits, with qualitative analysis of broader economic benefits.

Assessment of the costs and benefits

The benefits of the proposed amendments

5.4 The primary expected benefit of the Code amendment proposals is a modest reduction in the amount of security required for small retailers to meet their prudential requirements.

5.5 To assess the scale of benefits available we asked the clearing manager to model the reduction in total exit period exposure on a per retailer basis from reducing the post default exit period by four days. The model compared changes in exit-period spot purchases, spot sales and hedge amounts between the proposal and the status quo over the prudential period of 1 October 2025 – 10 November 2025 and an exit period of 11 November 2025 – 25 November 2025.

5.6 For all retailers, the simulation resulted in a stable mean reduction of 21% in total exit period prudential costs with a minimum of 20% and a maximum of 22%.

5.7 For retailers with 1,000 ICPs or fewer, this amounted to a combined reduction of $124,285 in required security for the period. As most of these retailers satisfy their prudential requirements entirely or predominantly by cash deposit, this is a direct cash expense that would no longer need to be accounted for under the proposal.

5.8 Further, for the modelling period, average adder inclusive exit period prices were relatively moderate (~$155). Exit period prices in more volatile seasonal periods often increase significantly beyond this, creating the likelihood of greater dollar amount reductions in relative required security over the course of the year.

5.9 For the specific inputs modelled (exit period purchases, sales and hedges), both exit period spot sales and purchases as well as hedges responded predictably to the shortening of the exit period window.

5.10 However, there remains a remote potential for slight variance in hedge based prudential amounts depending on the start and end dates of the contracts. During earlier sample testing (as noted in the issues and options paper), it was observed that if the exit period overlaps with a significantly favourable hedge contract window for a participant, shortening the exit period window can reduce the positive offsetting effect of that contract and potentially increase prudential requirements. This variance was not demonstrated to occur for any retailers with 1,000 ICPs or fewer.

5.11 The proposal to reallocate residual funds to wholesale market purchasers by proportion of total purchase volumes is expected to confer a small benefit to all purchasers (including retailers. It also establishes a more fair and principled basis for distribution by returning funds to the parties from whom they were originally sourced.

Economic benefits

5.12 The Authority's quantitative analysis addressed only the value of the direct affordability benefits of the amendments. However, there are additional likely economic benefits that are more difficult to attach a monetary value to. These may include:

(a) Improved productive efficiency gains resulting from a reduction in retailer cost to serve.

(b) Improved retail competition resulting from a reduction of small retailers working capital being tied up in prudential security and freed for productive use.

(c) Improved retail market resilience and reduced likelihood of default resulting from decreased financial pressure on small retailers meeting their prudential requirements.

Costs of the proposed amendments

5.13 The Authority expects there only to be a one-off cost of approximately $109,000 to the clearing manager for implementation of the proposals.

5.14 We do not expect any ongoing costs. We also do not expect any costs to industry participants. The reduction of phase 2 of the trader default process by one day does slightly reduce the time period for customers of small defaulting retailers to negotiate a contract with new retailers however, we do not expect this to materially impact their negotiating positions.

The Code amendment proposal's benefits are expected to outweigh its costs

5.15 Based on our assessment of the costs and benefits of the proposals, the Authority considers the Code amendment proposal is likely to have a modest net benefit.

5.16 The immediate affordability benefit to retailers is likely to exceed the initial implementation cost to the clearing manager with the potential to compound due to greater cost savings for retailers in future periods of elevated exit period prices.

Q3. Do you agree the Authority has correctly identified the costs and benefits of the proposed amendment?

Q4. Do you agree the benefits of the proposed amendment outweigh its costs?

Alternative means for achieving the policy objectives

5.17 All alternative means for achieving the policy objectives (and alternative design options for the specific Code amendment proposals) are noted in the sections above. For the reasons discussed, the Authority considers the proposed amendment is preferable to the alternatives.

Q5. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option by reference to the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

The proposals are consistent with the Authority's statutory objective

5.18 Section 32(1) of the Act states 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).

5.19 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.

5.20 The Authority considers the Code amendment proposal is necessary or desirable to promote each limb of the statutory objective:

(a) competition would be improved in the retail electricity market because:

(i) reduced prudential requirements would free up cash-flow for investment in innovation and expansion activities

(ii) a more diverse pool of retailers (brought about by ensuring that smaller retailers can better enter and remain in the market) would increase consumer choice and increase downward pressure on retail prices

(b) reliability would be improved across the electricity industry because:

(i) to the extent that reducing prudential requirements eases financial pressure on retailers, there is less likelihood of participants exiting the market and generators incurring losses

(ii) broadly maintaining the risk profile of the prudential regime would continue to give generators the necessary credit confidence to make investment decisions which may improve security of supply

(c) efficiency would be improved across the settlement and prudential security framework because minimising the cost to retailers of providing sufficient security allows them to allocate more capital to their core business without needing new resources.

5.21 For the same reasons, the Authority considers that the proposed amendments are necessary or desirable to promote competition in the industry, reliable supply of electricity to consumers and efficient operation of the electricity industry under section 32(1) of the Act.

Q6. Do you agree the proposed amendment complies with sections 15(1) and 32(1) of the Electricity Industry Act 2010?

The proposals are consistent with the Code amendment principles.

5.22 When considering amendments to the Code, the Authority is required by its Consultation Charter to have regard to the following Code amendment principles, to the extent that the Authority considers them applicable. Table 2 (below) describes the application of the Code amendment principles in respect of this Code amendment proposal.

Table 5: Application of Code amendment principles

Principle	Consideration
1. Clear case for regulation:	The Authority will only consider amending the Code when there is a clear case to do so. Paragraph 3.5 of this paper sets out the specific issues the proposals is intended to address. In summary, the Authority considers that the current prudential settings are unnecessarily limiting the ability of small retailers to grow and compete in the retail market.

	The Authority considers the key benefit to be increased affordability of prudential requirements for small retailers and the costs to be a one-off implementation cost to the clearing manager.
2. 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 costs and benefits are set out and summarised in section 5 of the paper. The Authority expects the benefits to outweigh the costs.

Appendix A Proposed Code amendment

A.1 This appendix contains the Authority's proposed amendments to the Code.

A.2 Text or formatting is red underlined if it is to be added to the Code.

A.3 Text is shown in ~~red strikethrough~~ if it is to be removed from the Code.

Electricity Industry Participation Code 2010

Schedule 11.5

Process for trader or retailer event of default

4 Failure by defaulting trader or defaulting retailer to remedy event of default

(1) This clause applies if—

(a) 7 days or more have elapsed since the **Authority** gave notice to the defaulting **trader** or defaulting **retailer** under clause 2(1); and

(b) the **Authority** considers that—

(i) the defaulting **trader** or defaulting **retailer** has not remedied the **event of default** or, in the case of an event of default under clause 14.41(1)(b) in respect of which there is an unresolved invoice dispute under clause 14.25, has not reached an agreement with the Authority to resolve the event of default; and

(ii) the defaulting **trader** or defaulting **retailer** still has 1 or more contracts under which a customer of the defaulting **trader** or defaulting **retailer** purchases **electricity** from the defaulting **trader** or defaulting **retailer** or is still recorded in the **registry** as being responsible for 1 or more **ICPs**.

(2) The **Authority** must—

(a) give written notice to the defaulting **trader** or defaulting **retailer** that the **Authority** considers that this clause applies; and

(b) unless the **Authority** considers there is good reason not to, attempt to advise customers of the defaulting **trader** or defaulting **retailer** that the defaulting **trader** or defaulting **retailer** has committed an **event of default** and one or more of the following:

(i) *[Revoked]*

(ii) the customer should enter into a contract for the purchase of **electricity** with another **trader** or **retailer** by the date that is:

(A) 13 days after the day on which the **Authority** gave written notice to the defaulting **trader** or defaulting **retailer** under clause 2(1) if the defaulting **trader** or defaulting **retailer** is recorded in the **registry** as being responsible for 1,000 of fewer **ICPs**; or

(B) otherwise 14 days after the day on which the **Authority** gave written notice to the defaulting **trader** or defaulting **retailer** under clause 2(1):

(iii) if the customer fails to enter into a contract with another **trader** or **retailer** by that date, the **Authority** may assign the defaulting **trader's** or defaulting **retailer's** rights and obligations under the customer's contract with the defaulting **trader** or defaulting **retailer** to another **trader** under clause 5:

(iv) any other information the **Authority** considers appropriate.

(3) *[Revoked]*

(4) *[Revoked]*

5 Authority may assign contracts and ICPs

(1) This clause applies if, by the end of the 17th day after the defaulting **trader** or defaulting **retailer** was given notice under clause 2(1), or the end of the 13th day after the defaulting **trader** or defaulting **retailer** was given notice under clause 2(1) if the defaulting **trader** or defaulting **retailer** is recorded in the **registry** as being responsible for 1,000 or fewer **ICPs**,—

(a) the defaulting **trader** or defaulting **retailer** has not remedied the **event of default** or, in the case of an event of default under clause 14.41(1)(b) in respect of which there is an unresolved invoice dispute under clause 14.25, has not reached an agreement with the **Authority** to resolve the **event of default**; and

(b) the defaulting **trader** or defaulting **retailer** continues to have 1 or more contracts under which a customer of the defaulting **trader** or defaulting **retailer** purchases **electricity** from the defaulting **trader** or the defaulting **retailer** or the defaulting **trader** is still recorded in the **registry** as being responsible for 1 or more **ICPs**.

(2) The **Authority** may—

(a) exercise its right under a contract under which a customer purchases **electricity** from the defaulting **trader** or defaulting **retailer** to assign the rights and obligations of the defaulting **trader** or defaulting **retailer** under the contract to a recipient **trader** in accordance with the contract; and

(b) assign an **ICP** to a recipient **trader** and direct the **registry manager** to amend the record in the **registry** so that the recipient **trader** is recorded as being responsible for the **ICP**; and

(c) specify the recipient **trader** to whom the rights and obligations under the contract or the **ICP** will be assigned.

(2A) When determining an assignment under subclause (2), the **Authority** may do 1 or both of the following:

(a) exercise its discretion to determine the recipient **trader** without going through a tender or other competitive process:

(b) undertake a tender or other competitive process to determine the recipient **trader**.

(3) The **Authority** must, by notice in writing to each recipient **trader**, direct the recipient **trader** to accept an assignment under subclause (2).

(4) Before the **Authority** gives notice to a recipient trader under subclause (3), the **Authority** may decide not to assign rights and obligations of the defaulting **trader** or defaulting **retailer** under a contract or an **ICP** to a recipient **trader** if the recipient trader satisfies the **Authority** that the assignment would pose a serious threat to the financial viability of the recipient **trader**.

(5) A recipient **trader** must comply with a direction given to it under subclause (3).

(6) The **registry manager** must comply with a direction given to it under subclause (2).

(7) Before the **Authority** exercises its right to assign rights and obligations or an **ICP** under subclause (2), the **Authority** must, if the **Authority** considers it is practicable, consult with the defaulting **trader** or defaulting **retailer** as to the need for the notice.

Part 14

Clearing and Settlement

14.34A Payment of residual funds from operating accounts

(1) In this clause,—

(a) applicable period means the period from the last date the **clearing manager** determined the amount of residual funds to be paid to each **participant** under subclause (3), if applicable, up to the date the **clearing manager** determines the amount of residual funds to be paid to each **participant** under subclause (3):

(b) residual funds means any monies left in the **clearing manager's operating accounts** after all amounts owed by the **clearing manager** have been paid in accordance with this Part, less—

(i) any applicable deduction for tax purposes; and

(ii) any amounts that are allocated to be paid to **participants** in accordance with this Part that have not yet been paid; and

(iii) any amounts required to pay any bank fees due for the next two months for the **operating account**; and

(iv) any amounts required to maintain a positive balance in each **operating account** at a level that the **clearing manager** considers is reasonably prudent.

(2) The **clearing manager** may use monies in the **operating accounts**, that are not paid or due to be paid to **participants** in accordance with this Part, to pay any bank fees due or applicable tax owing for the **operating accounts**.

(3) The **clearing manager** will determine the amount of residual funds to be paid to each **participant** in accordance with subclause (4) as follows:

(a) by determining the amount of residual funds available in its **operating accounts**:

(b) by identifying the **participants** that ~~the~~ have paid the **clearing manager** ~~has paid~~ in accordance with ~~clause 14.20(2)(a),~~ clause 14.19(2)(a), other than **grid owners**, in the applicable period:

(c) by allocating the residual funds available to the **participants** identified under paragraph (b), in direct proportion to the amount the ~~**clearing manager**~~ each **participant** has paid ~~each **participant**~~ the **clearing manager** in the applicable period compared to the total amount ~~the **clearing manager**~~ all **participants** identified under paragraph (b) have ~~has~~ paid ~~all **participants**~~ the **clearing manager** in accordance with ~~clause 14.20(2)(a)~~ clause 14.19(2)(a)~~, other than **grid owners**,~~ in that period:

(d) by deducting, from any residual funds allocated to a defaulting **participant** under paragraph (c), any amount the **clearing manager** sets-off against the unpaid amount payable by the defaulting **participant** to the **clearing manager** under clause 14.44(1)(c):

(e) by rounding down the amount allocated to each **participant** to the nearest cent.

(4) At least once in each six-month period, but no later than 1600 hours on the final **business day** in the months of March and September, the **clearing manager** must—

(a) advise each **participant** that the **clearing manager** has paid in accordance with clause 14.20(2)(a) in the **applicable period**, other than **grid owners**, of the amount of residual funds to be paid to that **participant**, as determined under subclause (3); and

(b) pay the residual funds to each **participant** in accordance with subclause (3).

Part 14A

Prudential Requirements

14A.17 Participants subject to prudential requirements must provide information to clearing manager

(1) The **clearing manager** may require a **participant** that is required to comply with prudential requirements in this Part to provide, by any date specified by the **clearing manager**, any information that the **clearing manager** requires for the purposes of carrying out its functions under this Part.

(2) A **participant** that is required to provide information to the **clearing manager** under subclause (1) must provide the information to the **clearing manager** by the date specified by the **clearing manager**.

(3) Each **participant** that is required to comply with prudential requirements under this Part must provide the following information to the **clearing manager** immediately upon the **participant** becoming aware of the situation:

(a) if the **participant** is a **purchaser**, any significant change to that **purchaser's business**, including a merger or acquisition, loss or gain of a customer, or sale or purchase of assets, that could significantly affect the quantity of **electricity** purchased or generated by the **participant** in its capacity as a **purchaser** or **generator**:

(b) any change or likely change to the **participant's** credit rating (if the **participant** has a credit rating), regardless of whether or not the **participant** is relying on a credit rating as a prudential requirement in terms of clause 14A.3:

(c) if a letter of credit or guarantee or bond is provided in respect of the **participant** in accordance with Part 1 of Schedule 14A.1—

(i) any change or likely change to the credit rating of the provider of the guarantee, letter of credit, or bond such that the provider's credit rating would, as a result, not be an acceptable credit rating as defined in clause 14A.3; or

(ii) any claim by the provider of the guarantee, letter of credit, or bond that the guarantee, letter of credit, or bond has ceased to be valid and enforceable.

(d) if the **participant** is a **retailer**, any change to the number of **ICPs** the **retailer** is recorded in the **registry** as being responsible for, if that change will result in the **retailer**:

(ii) being responsible for 1,000 **ICPs** or fewer, if the **retailer's** post-default exit period is currently determined under clause 14A.22(4)(a)(ii); or

(ii) being responsible for more than 1,000 **ICPs**, if the **retailer's** post-default exit period is currently determined under clause 14A.22(4)(a)(i).

(4) If, at any time, a **participant** believes that its ability to pay an amount owing to the **clearing manager** under this Code is or is likely to be materially adversely affected, the **participant** must provide the **clearing manager** with details of that fact immediately.

14A.22 Clearing manager to keep register of specific time periods

(1) The **clearing manager** must keep a register of the following time periods for each **participant** that is required to comply with prudential requirements in this Part (except a **participant** to which subclause (2) applies):

(a) a prudential exit period determined in accordance with subclause (3):

(b) a post-default exit period determined in accordance with subclause (4).

(2) The **clearing manager** is not required to keep a register of time periods for a **participant** that is required to comply with prudential requirements in this Part only because the **participant** has an obligation in relation to 1 or more **FTRs**.

(3) The prudential exit period for a **participant** is the number of **trading days** that elapse over the sum of the following:

(a) 1 **trading day**:

(b) the post-default exit period for the **participant**.

(4) The post-default exit period for a **participant** is as follows, unless the **Authority** has approved a shorter period requested by the **participant**:

(a) for a **retailer**~~, 18 **trading days either:**~~

(i) 14 **trading days** if the **retailer** is recorded in the **registry** as being responsible for 1,000 **ICPs** or fewer; or

(ii) 18 **trading days** if the **retailer** is recorded in the **registry** as being responsible for more than 1,000 **ICPs**:

(b) for a **direct purchaser**, 7 **trading days**:

(c) for a **participant** that is not a **retailer** or a **direct purchaser,** 7 **trading days**.

(5) The post-default exit period for a **participant** begins from the day on which the **participant** advises the **clearing manager** or the **clearing manager** advises the **participant** under clause 14.43 that an **event of default** has occurred in relation to the **participant**.

(6) A **participant** that has a shorter post-default exit period approved by the **Authority,** may increase the period to no more than the number of **trading days** set out in subclause (4) by giving 20 **business days'** notice to the **clearing manager**.

(6A) A **retailer** to whom subclause (4)(a)(i) applies may increase the post-default exit period to no more than 18 **trading days** by giving 20 **business days'** notice to the **clearing manager.**

(7) A shorter post-default exit period approved by the **Authority** takes effect 20 **business days** after the date of the **Authority's** approval.

(7A) The post-default exit period under subclause (4)(a)(i) takes effect 20 **business days** after the date a **retailer** advises the **clearing manager** that it is recorded in the **registry** as being responsible for 1,000 **ICPs** or fewer.

(8) If the **Authority** has approved a shorter post-default exit period for a **participant**—

(a) the **participant** must immediately advise the **Authority** if the **participant's** circumstances change such that the criteria against which the **Authority** approved the shorter post-default exit period may no longer be met:

(b) the **clearing manager** must immediately advise the **Authority** if the **clearing manager** becomes aware that the **participant's** circumstances have changed such that the criteria against which the **Authority** approved the shorter post-default exit period may no longer be met:

(c) if the **Authority** considers the **participant's** circumstances have changed such that the criteria against which the **Authority** approved the **participant** having a shorter post-default exit period are no longer met, the **Authority** may—

(i) amend the **participant's** post-default exit period; or

(ii) rescind its approval of the shorter post-default exit period for the **participant**.

(9) If the Authority amends or rescinds its approval of a **participant's** shorter post-default exit period, the **Authority** must—

(a) give the **participant** at least 1 month's notice in writing before the amendment or the rescission comes into effect; and

(b) advise the **participant** of the reasons for amending or rescinding the approval.

Appendix B Submission form

Submitter	

Questions	Comments
Q1. Do you have any comment on the Authority's response to submissions?	
Q2. Do you agree with the objective of the Code amendment proposal? If not, why not?	
Q3. Do you agree the Authority has correctly identified the costs and benefits of the proposed amendment?	
Q4. Do you agree the benefits of the proposed amendment outweigh its costs?	
Q5. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option by reference to the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q6. Do you agree the proposed amendment complies with sections 15(1) and 32(1) of the Electricity Industry Act 2010?	