Code amendment omnibus #6: tie-breaker enhancement, materially large contracts, hedge disclosure obligations

Consultation paper

12 January 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is continuously reviewing the regulations for which it is responsible to ensure they support our evolving electricity sector. We use the omnibus process to consult at the same time on several discrete minor proposals to amend the Electricity Industry Participation Code 2010 (Code). This is timelier and more efficient than issuing separate consultation papers.

In this omnibus process we mainly propose changes to market settings and policy related to trading arrangements in part 13 of the Code, along with technical and non-controversial changes throughout the Code. The Authority will consider submissions and issue a decision by May 2026.

Section 1 of this consultation paper explains the purpose of the paper and how you can inform our thinking by submitting feedback on our proposals.

Minimum offer price exclusions for tie-breaker solutions

Section 2 proposes changes to Part 13 of the Code to exclude intermittent generators from submitting zero-price offers. Our proposal comes after we received a Code amendment request from the System Operator in October 2025.

The change is intended to improve how the market handles tie-breaker situations, which is when multiple generators offer the same price at locations with limited transmission capacity.

Currently, these situations require manual intervention by the System Operator to maintain system security and operational stability. The System Operator will introduce an automated tie-breaker mechanism in June 2026 to allocate capacity proportionally among generators offering the same price. However, this mechanism does not distinguish between generation types. As a result, the solution does not address the reliability considerations the System Operator currently manages through discretion.

Our proposal to exclude intermittent generators from submitting zero-price offers builds on the System Operator's tie-breaker approach. Under this approach, less flexible generation (such as geothermal or thermal plants at minimum generation levels) is prioritised over more flexible intermittent generation like wind or solar. The ability to do this automatically is important at times when load is low and some generation needs to be constrained down, but increased resources are needed later to meet a demand peak. If the less flexible plant were constrained down, it would have to shut down. Once shut down, these plants cannot restart quickly, reducing the system's ability to meet later demand and increasing operational risk. Prioritising less flexible generation will support system security and operational stability.

This proposal will provide clearer, more consistent outcomes for participants, reduce reliance on manual discretion, and support reliability and efficiency in the electricity market.

Appendix A includes the proposed Code amendments.

Materially large contracts

Section 3 proposes changes to Part 13 (subpart 7) of the Code to clarify and simplify the rules on materially large contracts (MLCs), ensuring they remain effective and easy to apply. These provisions currently restrict generators from entering into large contracts unless certain conditions are met, to prevent inefficient price discrimination that could impact consumers.

The Authority's proposal includes updates to the definition of a MLC, clarifying treatment of new generation, and options for calculating offsets for intermittent generation like wind and solar.

These changes aim to support investment in new generation, reduce barriers for renewable projects, and maintain safeguards against inefficient price discrimination. Greater clarity will better support the intent of the MLC rules, which promotes competition, reliability and efficiency for the long term benefit of consumers.

If the Authority adopts the proposed Code amendments, we will publish a guidance document to provide further detail on how the Authority expects these aspects of the MLC provisions to work in practice.

Appendix B includes the proposed Code amendments.

Refining hedge disclosure obligations to increase transparency

Section 4 proposes improvements to the hedge disclosure obligations in Part 13 of the Code to strengthen these obligations and improve transparency in the over-the-counter market. The proposed changes respond to operational issues identified since the 2024 reforms and aim to ensure hedge disclosure requirements remain fit-for-purpose.

A robust fit-for-purpose hedge disclosure regime will increase transparency in the over-the-counter market, enhance confidence in market competitiveness, and strengthen regulatory oversight.

The key proposals include measures to improve identification of power purchase agreements and firming arrangements, introduce clear timeframes and processes for disclosing novel contracts, and require participants to provide consistent information on demand response arrangements.

The objective of these proposals is to ensure a robust set of hedge disclosure obligations that enhance transparency and confidence in the market. Further changes to hedge disclosure obligations may be required to support monitoring of the proposed non-discrimination obligations, subject to consultation feedback and final decisions.

The paper also includes technical and non-controversial changes to the hedge disclosure obligations under section 39(3)(a) of the Act, to correct an error in a formula and to clarify the operation of some provisions. The final two proposals are changes to guidance only. The Authority is not required to consult on these changes but is happy to receive any comments stakeholders may have on them.

Appendix C includes the proposed Code and guidance amendments.

Technical and non-controversial amendments

Section 5 explains that the Authority is proposing a list of minor corrections to the Code to improve clarity and accuracy. These changes include fixing outdated references, correcting formatting issues, modernising formulae and removing definitions that are no longer needed. They address issues identified as part of our project to bring the Code online.

These amendments are technical and non-controversial and do not change the meaning or intent of the Code. While consultation is not required for these updates, feedback is welcomed to ensure the Code remains clear and consistent.

Appendix D includes a table of the proposed technical and non-controversial Code amendments.

Feedback on the proposals is due by 23 February 2026

We welcome feedback on any or all sections of the omnibus by **23 February 2026**. We will consider all submissions before making our final decisions. We also welcome feedback on the format of the omnibus consultation and possible improvements for the future.

Contents

1. Purpose

We are seeking your views on three different proposals

1.1. The purpose of this paper is to consult with interested parties on the Authority's proposals to:

(a) apply minimum offer price exclusions in tie-breaker situations

(b) clarify and simplify the rules on materially large contracts

(c) refine hedge disclosure obligations to increase transparency.

1.2. These proposals are being presented in omnibus form to streamline the number and frequency of consultations on Code amendment proposals. This paper is the sixth in the series. We use omnibus consultations to consolidate discrete Code amendment proposals when appropriate to do so.

1.3. Each proposal is set out in a separate section of this paper, along with a regulatory statement for each proposal. The regulatory statement includes:

(a) a statement of the objectives of the proposed amendment

(b) an evaluation of the costs and benefits of the proposed amendment

(c) an evaluation of alternative means of achieving the objectives of the proposed amendment.[1]

1.4. The draft wording of each proposed Code amendment is included in appendices A to C.

1.5. This paper also proposes a list of technical and non-controversial Code amendments. These amendments do not require consultation, but we welcome feedback on the proposals. These are included in Appendix D.

How you can inform our thinking

Submissions can be made using our template

1.6. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix E. Submissions in electronic form should be emailed to OperationsConsult@ea.govt.nz with "Omnibus #6 consultation" in the subject line.

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

Your submission will be published, may be shared with other organisations, and can be requested under the Official Information Act

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:

[1] As required under section 39 of the Act.

(a) indicate which part should not be published,

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

(c) 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, 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.

1.11. The Authority may also share submissions or other information, including parts of submissions not published, with another public service agency, statutory entity, the gas industry body or an overseas regulator in accordance with section 47A of the Electricity Industry Act 2010. The Authority would only do so if the submissions or other information could assist that organisation in the performance of its functions, and if it is satisfied that are appropriate protections in place for maintaining the confidentiality of anything provided (including information that is personal within the meaning of the Privacy Act 2020).

Feedback on proposals is due by 23 February 2026

1.12. Please deliver your submission by **5pm on Monday 23 February 2025**.

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

2. Minimum offer price exclusions for tie-breaker situations

The existing arrangements – discretion by the System Operator to resolve tie-breaker situations

2.1. A core responsibility for the System Operator is to ensure that the market scheduling and dispatch process captures the physical constraints of the power system.

2.2. The Code requires the System Operator to schedule and dispatch generation to maximise the gross economic benefits for all purchasers. This requirement is called the Dispatch Objective[2] and is subject to the offered capacity of the transmission grid and dispatched resources, achieving the Principal Performance Obligations (PPOs) and restoration requirements.

2.3. The System Operator may apply further constraints on the dispatch solution to comply and plan to comply with the PPOs. Particularly, the constraints applied should allow the System Operator to ensure transmission assets do not become overloaded, and the system remains in a stable operating state. A consistent dispatch solution is important to meet these criteria and avoid unexpected system configurations.

2.4. The Must Run Dispatch Auction (MRDA) allows generators to improve their chances of being dispatched by securing rights to offer at $0/MWh. Some generation is considered must run because it cannot reduce output without breaching resource consents or facing operational risks. However, as the MRDA operates at a national level, it does not specifically account for regional transmission constraints.

2.5. The System Operator has defined an oversupply (tie-breaker) situation as being one that occurs when more equally priced generation is offered at a single location than can be dispatched due to a network export limit.

2.6. Neither the Code nor market systems currently resolve tie-breaker situations automatically. While the Scheduling, Pricing and Dispatch (SPD)[3] model will solve the market optimisation as it is required to, it is uncertain ahead of time what solution it will schedule. This is because all possible solutions in a tie-breaker situation are equally optimal. One offer may fully clear while another may partially clear. This process is non-deterministic and outcomes can vary from interval to interval and schedule to schedule.

2.7. These situations are not yet widespread or frequent, but the System Operator expects them to increase in the future.[4] As a result, generator owners and investors are increasingly seeking clarity and confidence on how tie-breakers are, or will be, resolved by the System Operator.

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2 Clause 13.57 of the Code describes the Objective Function, which is encoded into SPD as the outcome it must achieve. Further details on the Objective Function and modelling system (SPD), including a mathematical representation of the Objective Function, are contained in Schedule 13.3 of the Code.

3 Further description of the SPD model can be found here: Software specifications | Transpower. An overview of SPD can be found here: SPD101 | Transpower

4 For example, there is evidence that periods of zero or near zero spot prices are increasing e.g. see Extreme low prices – the less-scrutinised side of electricity price volatility

The System Operator uses discretion to manually resolve tie-breaker situations

2.8. Currently, there is no defined process for resolving tie-breaker situations, so the market system cannot handle them consistently or equitably.

2.9. Therefore, a tie-breaker situation at a single pricing node may require resolution in real time, or close to it, by the System Operator, particularly where generation type differentiation or operational constraints must be considered. This involves using discretion to allocate the available dispatch capacity between the relevant generators or purchasers.

2.10. If System Operator discretion is needed, those decisions are typically guided by system security considerations. These considerations include generation certainty and physical system needs. This tends to happen particularly for inflexible generators with start-up requirements or minimum operating levels. If these units are constrained down during low-load periods, they may be forced to shut down and cannot return in time to meet the later demand peak. Prioritising these units support system security and reduces operational risk.

2.11. The use of discretion can help the System Operator maintain compliance with their PPOs.[5] However, this method of resolution creates ambiguity and reliance on System Operator discretion. It has the potential to result in inconsistent and less predictable dispatch decisions. This in turn may cause uncertainty for generators about how much of their offered generation will be dispatched when more equally priced generation is offered at a single location than can be dispatched.

The System Operator consulted on a tie breaker solution and intends to implement by 30 June 2026

2.12. In July 2025, the System Operator consulted on implementing tie-breaker provisions in the market system.[6] It sought feedback on how tie-breaker situations should be resolved for multiple competing generator offers in the wholesale electricity market. The System Operator has decided to implement its proposed tie breaker solution by 30 June 2026.

2.13. A new tie-breaker energy constraint will be added to the SPD model. When multiple generators offer the same price at a constrained location, the system will split the available transmission capacity proportionally based on the offer quantity at the tied price.

2.14. This change will not prioritise generation dispatch by type of generation. It treats all equally priced offers the same.

2.15. The focus of the System Operator's tie-breaker provisions is on providing greater certainty ahead of time. The aim is to ensure consistent, efficient, transparent and

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5 Clause 13.70 of the Code allows the system operator to exercise discretion to depart from the dispatch schedule if it is necessary to meet the dispatch objective or to meet the requirements of clause 8.5 in relation to restoration of the power system.

6 Evolving market resource co-ordination: Tie-breaker provisions

predictable dispatch outcomes, while reducing reliance on discretionary action by the System Operator.

Problem definition – inefficient resolution of tie-breaker situations

The System Operator submitted a Code amendment request to enable the use of offer prices to distinguish between generation types

2.16. The System Operator proposed a Code amendment to the Authority seeking to further improve dispatch efficiency, reduce reliance on its discretion, and enhance market transparency. The System Operator's proposal is designed to complement its tie breaker solution described in paragraphs 2.12 to 2.15. It aims to improve certainty, transparency, and efficiency in dispatch decisions through differentiating between generation types, which is something its tie-breaker solution cannot do.

2.17. The System Operator's Code amendment request (CAR) proposes a minimum offer price of $0.01/MWh for intermittent generation. It believes this would allow the market-clearing process to automatically resolve tie-breaker situations without relying on operator discretion. By requiring intermittent generators to offer at a non-zero price, the system can differentiate between generation types and allocate dispatch more consistently.

2.18. The System Operator requested this Code amendment to enhance the automated resolution of tie-breaker situations. As set out above, these situations currently require manual intervention when more equally priced generation is offered than can be dispatched due to network constraints.

2.19. When the System Operator makes manual decisions, it usually prioritises dispatch for generators with significant operational constraints (like geothermal or thermal plants that can't easily stop or restart). Intermittent generation eg, wind or solar is more likely to be reduced instead. This is because turning off the operationally constrained generators could cause reliability or operational problems.

2.20. The System Operator considers the changes to the Code to be minor because most intermittent generators already offer at or above $0.01/MWh, and historical data shows very few zero-price offers. The System Operator believes this amendment will promote competition, support reliability by reducing risks of inappropriate dispatch, and improve efficiency by automating processes that are currently manual.

2.21. Table 1 provides a summary of the System Operator's tie-breaker solution and its Code amendment request to the Authority.

Table 1: Summary of the System Operator's tie-breaker solution vs its Code amendment request

	System Operator's tie-breaker provisions	System Operator's Code amendment request to Authority
Purpose	Provide a consistent way to allocate MW when multiple generators offer the same price at a constrained location.	Automate prioritisation of generation types with operational constraints (e.g., geothermal) ahead of intermittent generation.

How it works	Split MW based on size of each offer at the same price. Adds a tie-breaker energy constraint in the SPD model to pro-rate MW based on offer size at the same price.	Limit offer prices so the system knows which type to prioritise. Introduces restrictions on offer prices so the market-clearing process can distinguish between generation types.
Impact on Market Design	Works within the current market design.	Requires Code amendments.

The System Operator manages dispatch conflicts between intermittent and inflexible generation

2.22. Embedded intermittent generation can currently be offered at $0.00/MWh. The current offer structure does not adequately reflect key operational characteristics, such as minimum operating levels and minimum start times. This can lead to inflexible generators, such as geothermal or thermal generators with minimum operating levels, being dispatched down before intermittent generators. Geothermal and thermal generation types are often designed for continuous operation and cannot easily adjust output without risking equipment integrity or incurring lengthy restart times.

2.23. The System Operator is required to intervene if a generator invokes clause 13.82(2)(a) of the Code.[7] In response to a claim, the System Operator must perform a security assessment across multiple trading periods to decide on the best option. If the System Operator's assessment shows that the geothermal or thermal generation will be needed later, such as for a morning or evening peak, it may use its discretion by reducing intermittent generation instead.

2.24. In response to the System Operator's consultation on tie-breaker provisions,[8] several generators raised concerns about how geothermal and other inflexible plants are treated under dispatch arrangements. Submissions from Genesis, Mercury, Ngawha, Contact Energy, and Eastland Generation emphasised that generation types, such as geothermal and other inflexible plants, face operational constraints under current dispatch arrangements.

The System Operator expects increasing frequency of tie-breakers

2.25. In recent years, there has been an increase in tight capacity situations driven by increased peak demand, more intermittent generation, and insufficient flexible generation to cater for the increasing short-term supply variations.

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7 Generators can claim a bona fide physical reason to remain at their required operating level.

8 Consultation paper: Evolving market resource co-ordination_Tie-breaker provisions_Consultation Paper.pdf

2.26. The Authority's generation investment dashboard[9] indicates a significant increase in large-scale wind and solar generation expected to come online in the future. For example, as of December 2025, our investment dashboard estimates that over two thirds of all committed generation is intermittent. There is also significantly more actively pursued intermittent generation compared to other types. See the estimates for committed and actively pursued generation in Table 2 below.

Table 2: Estimates for committed and actively pursued generation by generation type as of 1 December 2025

	Committed (MW)	Actively pursued (MW)
Intermittent generation[10]	991	2,670
Firming generation[11]	390	277

Proposal – to exclude embedded intermittent generators from offering at $0

2.27. The Authority proposes to amend the Code to exclude intermittent generators from offering at $0/MWh.

2.28. We do not believe that dispatch notification generators that are also intermittent generators need to be excluded. This is because the System Operator can approve or revoke these applications and can consider any potential security implications as part of the approval process.[12]

2.29. We also propose to exclude intermittent generators[13] from bidding for MRDA rights. Auction rights to bid in the MRDA are awarded to the company (generator) rather than individual generating units. Our proposal would mean that if a generator secured the rights, it could not apply them to intermittent generation units in its portfolio.

2.30. See Appendix A for the proposed Code amendment.

2.31. This solution would ensure consistent outcomes from scheduling through to real-time dispatch and enable affected participants to better plan and manage their positions.

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9 The generation investment dashboard was published in July 2025. The dashboard uses data collected under the Authority's investment pipeline clause 2.16 notice, and is updated monthly. Generation investment pipeline | Electricity Authority

10 Intermittent generation includes solar and wind.

11 Firming generation has been classified in the Authority's investment pipeline to include thermal, geothermal and hydro generation. Although geothermal is usually treated as baseload because it runs continuously, it can also provide firming for renewables by maintaining output when wind or solar drops, similar to hydro.

12 As per clauses 84P and 84Q of the System Operator's Policy Statement.

13 Part 1 of the Code defines 'intermittent generator' to mean "the owner of an intermittent generating station. To avoid doubt, clauses referring to an intermittent generator apply only to the intermittent generating stations owned by the intermittent generator."

Impact on stakeholders: same outcomes using a different management approach

2.32. Intermittent generators are affected by the management of over supply situations. However:

(a) the proposed Code amendment would create the same outcomes for intermittent generators. It would only change how the System Operator manages tie-breaker situations, using less discretion and giving more certain and foreseeable outcomes for generators.

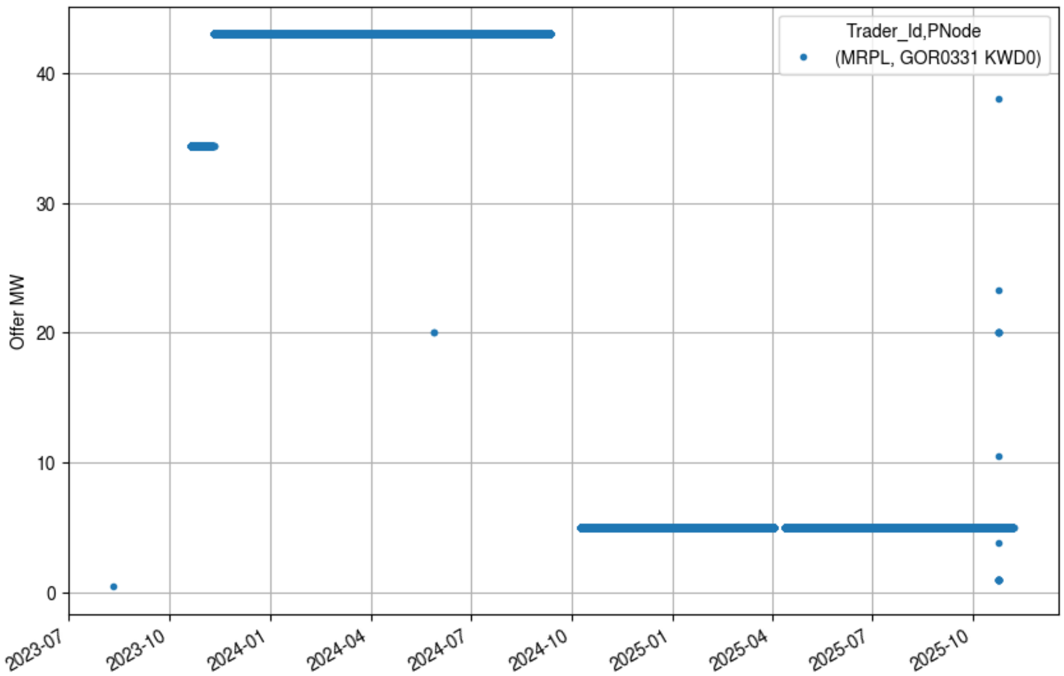
(b) since 2008, only one intermittent generator has made $0/MWh price offers. This intermittent generator's offers have been consistent but not continuous across all trading periods since July 2023 (see Figure 1).

(c) most of the time, intermittent generators are price takers, the price usually clears higher than $0.01/MWh. They are only likely to be impacted when prices are at $0/MWh.

2.33. Overall, these three factors suggest that most intermittent generators are unlikely to be affected by the change.

2.34. This proposal manages current power system needs where geothermal and thermal generation is still required to support peak demand and system stability.

Figure 1: Plot of one intermittent generator's zero-priced offers from July 2023 to November 2025



Q2.1. Do you support the Authority's proposal to amend the Code to exclude intermittent generators from offering at $0/MWh?

Please explain your answer.

Regulatory statement

Objectives of the proposed amendment

2.35. The objectives of the proposed Code amendment are to:

(a) give participants more certainty ahead of time

(b) make the dispatch process more consistent, efficient, transparent, and predictable

(c) reduce need for the System Operator use discretion and manual processes.

We expect the benefits of the proposed amendment to outweigh the costs

Benefits

2.36. The Authority's preliminary view is that the proposal would present a net benefit to consumers and participants. The System Operator presented benefits in its CAR which we largely agree with. The Authority therefore considers the main benefits of the proposal include:

(a) **Enhanced reliability of supply**:

(i) reduces the risk of inflexible generators with minimum operating levels from being dispatched off inappropriately, reducing the risk of plant instability or forced outages

(ii) reduces reliance on operator discretion and manual processes, which can introduce variability or errors, and impact on price signals

(iii) ensures the market dispatch process can efficiently manage tie-breaker situations, which is increasingly important as more intermittent generation comes online

(iv) supports security of supply by prioritising baseload resource and resource that provides inertia.

(b) **Greater operational efficiency**:

(i) improves dispatch efficiency by allowing the market-clearing process to more efficiently and consistently optimise based on offer prices

(ii) lowers the risk of inefficient or inconsistent outcomes from ad-hoc manual processes, supporting both short- and long-term efficient price signals

(iii) provides a level playing field by ensuring generators are dispatched based on their offers

(iv) encourages non-intermittent generators to secure auction rights in MRDAs to reflect their relative flexibility

(v) delivers fairer and more transparent market outcomes eg, through more transparent forward schedules.

Costs

2.37. We anticipate no material costs for the System Operator to develop or implement the proposed Code amendment.

2.38. Administrative fees are minimal from the Authority's perspective.

2.39. The cost of implementing a new Wholesale Information and Trading System (WITS) validation rule to support the intermittent generation offer price change proposal is expected to be minimal for NZX.

2.40. The System Operator identified in its CAR that most intermittent generators do not offer below $0.01/MWh, which we have verified. Therefore, we believe the proposal will improve dispatch efficiency without materially affecting overall economic outcomes.

Evaluation of alternative options – offering less time efficiency or more operational complexity

Alternative considered	Reason not preferred
Expand MRDA scope to include locational factors and prioritisation of certain generation types. These changes were identified in the System Operator's paper: Evolving market resource co-ordination Tie-breaker provisions: Summary and response to submissions	This approach would require significant changes to market design and the Code. It would involve complex coordination across multiple mechanisms, including embedded generation, tie-breaker provisions, and potential negative pricing. These changes would introduce high regulatory and operational complexity, increase development time, and risk misalignment with existing processes. The proposed Code amendment achieves the same objective with more efficiency and transparency.
Change the market design by introducing a tie-breaker solution prioritising different types of generation.	Although this option would directly address tie-breaker and allocation issues, it would require significant market design changes and time to implement. This option requires full market design review and Code amendments, with consequential system tool changes. This means that it would have a long lead time but it would potentially provide a durable solution. The proposed Code amendment can be implemented faster with lower cost while still achieving efficient allocation.
Model local networks to reflect losses, allowing differentiation between generation types through loss factors.	This option would partly address the issue by creating differentiation, but its effectiveness would be limited and it would introduce complexity outside the current market boundary. This option would not solve the problem when generators connected to the same local network have no loss difference between them. This option would require fundamental changes to current modelling, as assets outside the market boundary would need to be represented and would influence pricing. There would therefore be high implementation costs and complexity. The proposed approach would avoid the need for fundamental modelling changes outside the market boundary, reducing complexity and implementation risk.

Assessment of the proposed Code amendment against section 32(1) of the Act

2.41. The Authority considers that the proposed amendment is consistent with section 32(1) of the Act. Enhancing the automation of the resolution of some tie-breaker situations is consistent with our main statutory objective because it would promote:

(a) **reliable** supply of electricity to consumers by strengthening system stability and reducing operational risks, ensuring consumers receive a reliable supply of electricity

(b) **efficient** operation of the electricity industry by improving how the market operates, optimising dispatch and reducing inefficiencies.

Assessment of the proposed Code amendment against Code amendment principles

2.42. The Authority is satisfied the proposed Code amendment is consistent with the Code amendment principles. In particular, the proposed Code amendment:

(a) addresses a problem created by the existing Code requiring an amendment

(b) provides an efficiency gain in the electricity industry for the long-term benefit of consumers.

Q2.2. Do you agree the proposed amendment is preferable to the alternative options?

If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

Q2.3. Do you agree with the analysis presented in this Regulatory Statement?

If not, why not?

3. Improving clarity of the materially large contracts provisions

The existing arrangements

3.1. Part 13, subpart 7 of the Code prohibits generators from giving effect to materially large contracts (MLCs) unless certain conditions are met, imposes information disclosure requirements to support compliance with these restrictions, and provides a clearance regime. These provisions address the incentive for generators (in some circumstances) to provide inefficient subsidies to *large load users*, resulting in *other consumers* facing higher prices than they otherwise would in an efficient market.

3.2. The Code prohibits generators from giving effect to MLCs unless the net value from the contract to the generator is positive relative to the alternatives or the buyer can on-sell unused electricity under the MLC on no worse terms than if they had consumed the electricity themselves.

3.3. The Code also provides the Authority with greater visibility of MLC contracts for the purposes of monitoring and compliance through the disclosure obligations. A voluntary clearance process is also set out in the Code which gives generators the option to gain assurance that a MLC is not in breach of the Code and that the Authority will not investigate a contract later.

Problem definition – interpretation and applications of the provisions

3.4. Since the implementation of the MLC provisions in 2023, the Authority has received queries from participants regarding how it interprets and applies certain provisions, particularly around intermittent generation offsets and contracts linked to new investment.

3.5. The Authority has also identified some clauses where discrete Code amendments supported by guidance would be beneficial for all participants, including issues discussed by the Authority in its April 2023 MLC Decision Paper.[14]

Proposal

3.6. The Authority is proposing to make some discrete Code amendments supported by guidance. The purpose of these proposed changes is to provide greater clarity to participants and other interested parties on how to interpret and apply the MLC Code provisions. We explain each proposed Code amendment in detail below.

The definition of a materially large contract

3.7. The Authority is proposing to amend clause 13.268(1)(a), which specifies what a MLC is.

3.8. Clause 13.268(1)(a) currently states that a materially large contract is:

(a) a contract that—

(i) is not entered into through a derivatives exchange; and

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14 Decision_paper_-_Inefficient_price_discrimination_in_very_large_electricity_contracts.pdf

*(ii) includes terms under which the **buyer** itself will consume **electricity**; and*

*(iii) relates to a net quantity of **electricity** that equals or exceeds 150 **MW** consumed at a point in time…*

3.9. A key objective of the current MLC provisions is to minimise unnecessary compliance and administrative costs by targeting only those arrangements that pose genuine risks of inefficient price discrimination. Inefficient price discrimination occurs where a generator offers a discounted price to a large load user as an inducement to stay, where that large user may otherwise exit or reduce its consumption.

3.10. The Authority considers that contracts where the load user pays at least the spot price or an exchange traded price cannot be the source of an inducement to stay as they result in the load customer paying market price.

3.11. Therefore, the Authority is proposing to amend clause 13.268(1)(a) to clarify that a MLC does not include:

(a) a bilateral contract where the final price the buyer pays (accounting for any form of discount) is at least the same as an equivalent exchange-traded derivative or derivatives; or

(b) a bilateral contract where the final price the buyer pays (accounting for any form of discount) is at least the spot price.

The impact of investing in new generation

3.12. The Authority is proposing to amend clause 13.268(4) which relates to the treatment of "new generation".

3.13. Clause 13.268(4) currently states:

*For the purpose of subclause (1)(a)(iii), the net quantity of **electricity** is the total **MW** consumed at a point in time (calculated in accordance with subclause (3)) less any **MW** generated from new generation, where the **materially large contract** is material to the **generator's** decision to invest in the new generation.*

3.14. The Authority proposes to amend this clause to address the issues discussed below.

Providing effective offsets for intermittent generation

3.15. Whether a contract is a MLC is determined based on the maximum possible quantity of electricity consumed "at a point in time" over the life of the contract, with any MW generated from new generation able to be offset against electricity consumed via clause 13.268(4). A single instance of the net quantity of electricity exceeding 150MW over the term of the contract is all that is required for the contract to be defined as a MLC.

3.16. This creates an issue as intermittent forms of generation can often be near zero in any trading period, meaning there could be no, or very little, offset provided by new intermittent generation at the point in time that the net quantity of electricity is assessed. There is therefore a risk that arrangements which might be beneficial as they encourage investment in new intermittent generation may be discouraged through being caught by the MLC provisions.

3.17. This is because the Code currently does not recognise an offset in proportion to the level of additional generation over the life of the contract. Rather, it looks at the 'worst case' in terms of net quantity of electricity across all trading periods, which is likely to be when the offset from new generation is at its lowest (so, for intermittent generation, when it is not producing). Any offset is therefore expected to be trivial irrespective of the installed capacity and expected levels of generation over the life of the contract.

3.18. When considering the offset provided by new intermittent generation, the following contract types should be considered:

Contract type	Description
Generation following	The buyer adjusts consumption to align with the generator's output. The generator commits to supplying a set percentage of the energy produced by a specified generating asset during each trading period at the agreed contract price.
Load following	The generator adjusts its output to match the buyer's actual demand. The generator guarantees the contract price and/or the required volume based on the buyer's consumption.
Fixed volume	A constant electricity commitment for the duration of the contract, which may include predefined step-up or step-down options.
Variable volume	The contracted volume varies according to a specific factor, typically the buyer's load or actual generation during a given period.

3.19. The offset provided by new intermittent generation may not be problematic for 'generation following' contracts.[15] However, it raises challenges for 'load following' and fixed volume contractual arrangements with buyers of a size greater than 150MW.

3.20. The Authority proposes amending the Code to address this issue by providing generators with the option to use a median offset in all trading periods, after the date of commissioning of the new generation, for "any MW generated from new generation" for the purposes of determining the "net quantity" in clauses 13.268(1)(a)(iii) and 13.268(4).

15 The Authority considers the current netting provisions in the Code work satisfactorily for generation following contracts. At all points in the life of a 'generation following' contract, the contractual obligation to supply is not greater than the actual generation from the new generation. In these cases, to satisfy clauses 13.268(1)(a)(iii) and 13.268(4), all the generator needs to show is that the contract is of a generation following type (with obligations less than 100% of total generation in any trading period, such that net consumption is never positive), and that the contract was material to the decision to invest.

3.21. The generator would use data specific to the location and technology deployed to arrive at an offset allowance equal to the median MW generation from the new investment. This amendment is expected to be most useful for wind and solar generation, but generators may choose to use this option for quantifying new generation from other types of generation.

3.22. In the case of wind, the median generation from the new investment could be estimated using site-specific historic wind data, for a period of at least three years, and translating this to a generation profile, having regard for the efficiency of the proposed technology and other relevant factors.

3.23. For solar, the new generation could be estimated using historic irradiance data — either site-specific or from a nearby location — covering at least three years. As with new wind generation, this data could then be converted into a generation profile, taking into account the efficiency of the proposed technology and other relevant factors.

3.24. The Authority could seek information on these 'median' calculations to consider whether the offset has been appropriately applied and therefore whether or not the contract(s) reach the MLC threshold.

3.25. Types of generation other than wind and solar seeking to rely on the proposed provisions would need to derive generation profiles appropriate to that form of generation.

Q3.1. Do you agree there is an issue with how the current Code recognises the benefits of new generation, most notably for wind and solar, for the purposes of determining whether an arrangement constitutes a MLC?

If not, why not?

Options for deriving "net quantity of electricity" in clause 13.268(1)(a)(iii), by netting of new generation under clause 13.268(4)

3.26. The Authority is proposing to amend clause 13.268(4) which relates to the "net quantity of electricity" in clause 13.268(1)(a)(iii), to address the concerns noted above regarding providing effective offsets for intermittent generation.

3.27. Clause 13.268(1)(a)(iii) currently states that:

*A **materially large contract** is a contract that relates to a net quantity of **electricity** that equals or exceeds 150 **MW** consumed at a point in time.*

3.28. The Authority considers there to be two options for this – either clause 13.268(4) could remain as is with no further provision for new intermittent generation (the status quo) or an amendment could be made to recognise intermittent generation arising from new investment (option 2 below).

Option 1: Status quo

3.29. As noted above, the current MLC provisions can be interpreted as requiring the use of a 'worst case' scenario when assessing whether a contractual arrangement falls within the MLC definition, which for new intermittent generation will likely mean when it is not generating.

3.30. The status quo prioritises addressing the harm to consumers from potential inefficient price discrimination, by way of a broad definition of the contractual arrangements subject to the restrictions on a MLC in clause 13.269. However, large contracts with buyers can be used to de-risk and attract further investment in generation. Such contracts may face undue barriers and uncertainties under the status quo — something the inefficient price discrimination policy rationale sought to avoid, given the long-term benefits to consumers of new and efficient investments in generation.

Option 2: Recognise the generation arising from new investment

3.31. The MLC provisions sought to recognise generation that reflects improved supply conditions, which was the reason for the offset provided by clause 13.268(4). Compared to a counterfactual scenario where the same contract exists between the generator and buyer but without the new investment, the addition of new generation enhances supply. This can lower the expected spot price for all consumers, partly negating the impact of any price discrimination.

3.32. However, for the reasons set out above, the status quo does not provide a meaningful offset for new intermittent generation and therefore does not materially differentiate contractual arrangements which attract new intermittent generation from those that do not.

3.33. The Authority is therefore proposing to amend the Code as described at paragraph 3.20 above. This can be expected to remove barriers, and improve incentives, to invest in new generation.

3.34. The benefits from providing an offset equal to median generation for all trading periods arising from new investment must be considered against the increased risk of inefficient price discrimination. By narrowing the circumstances in which the MLC provisions apply, there is a risk that arrangements which should properly be viewed as inefficient price discrimination would fall outside of those provisions.

3.35. However, the Authority considers this risk can be effectively mitigated through a robust, evidence-based approach to calculating applicable offsets. A well-designed framework would help ensure the intended benefits are determined without undermining the integrity of the regime. We will be providing guidance on how we would expect to see an offset calculated.

3.36. This proposal does not preclude generators from using other methodologies that measure new generation for each specific trading period (provided that they comply with the relevant provisions), which may be preferable for ‘generation following’ type contracts, for example. The Authority considers this option may be attractive to generators using new generation to support fixed or load following contracts.

3.37. The Authority currently prefers Option 2.

Q3.2. Do you prefer Option 1, Option 2, or an alternative option?

Please explain your answer.

Additional work required if the Authority implemented Option 2

3.38. There are several matters that would need to be addressed if the Authority implemented Option 2:

(a) What and how much data (site-specific or from a nearby location) is required to inform offset allowances for different types of generation?

(b) What metric should be used for setting the offset allowance?

(c) How should staged implementations of new investments be treated?

Defining the offset allowance

3.39. The Authority proposes that the expected electricity generation profile from new generating assets be calculated using models and methodologies aligned with prevailing industry standards for each energy type. Generators would have flexibility in their chosen approach but must ensure compliance with established market standards to produce robust, bankable generation estimates that account for relevant operational and environmental factors, including climate variability. For example:

(a) wind: At least three years of site-specific wind speed and direction data, compliant with IEC 61400-12-1, correlated with long-term reference data to account for climate oscillations like El Niño Southern Oscillation and Southern Annual Mode

(b) solar: A minimum of three years of Global Horizontal Irradiance data — either site-specific or from a nearby location — adhering to ISO 9060:2018, supplemented by satellite models

(c) geothermal: Well test data (temperature, pressure, flow rates) per NZS 2403:2015, with reservoir modelling for long-term yield.

3.40. The standards listed above are illustrative of current best practices for each generation type, noting that industry standards may evolve over time and that multiple evidence-based methodologies may exist for each energy type, and generators must select and justify their chosen approach.

Q3.3. Do you agree that offsets claimed for new generation should be calculated using prevailing industry standards and methodologies specific to each generation type (eg, wind, solar and geothermal)?

If not, please explain your reasons and suggest any alternative approaches.

Setting the offset allowances

3.41. The proposed Code change would provide generators with a choice of approach for calculating the offset used to reflect the MW generated from new generation:

(a) **Median generation offset** – Under the proposed clause 13.269(5), generators could apply an offset equal to the median expected generation from a new asset over the MLC's duration.[16] This offset would be a constant value in all trading periods equal to the median expected new generation over

[16] A mean-based approach is not favoured given the skewed nature of generation from intermittent assets. Moreover, the GWAP/TWAP is typically less than 1.

the life of contract and would be derived using models and methodologies aligned with prevailing industry standards (see previous section).

For example, for a new wind farm, a generator might choose to calculate the median generation using at least three years of site-specific wind data, compliant with IEC 61400-12-1, converted into a generation profile for the national grid, accounting for the proposed technology's efficiency, climate oscillations and other relevant factors. This option may be attractive to generators using new generation to support fixed or load following MLCs.

(b) **Each point in time offset** – Under the proposed clause 13.269(6), generators could apply an offset equal to the expected actual generation from a new asset for each trading period, using industry standard methods. This approach may be preferred for 'generation following' MLCs, but the generator may also choose it for other contract types.

Q3.4. Do you agree with allowing generators to choose between median generation and each point in time offsets?

If not, please explain your reasons and suggest any alternative approaches.

Logical flaw in clause 13.268(4)

3.42. Clause 13.268(4) was intended to assist in determining whether a contract qualifies as a MLC by allowing an offset to reflect new generation. However, a logical flaw exists in its wording – it states that the offset is only permitted where the "materially large contract is material to the generator's decision."

3.43. This creates a tautology, as it implies the offset only applies to contracts already classified as MLCs, undermining the clause's purpose of using the offset to evaluate MLC status in the first place. The Authority proposes that this issue be resolved by replacing the phrase "materially large contract" with simply "contract", ensuring that the offset for new generation is considered when assessing any contract for MLC status.

3.44. This correction would eliminate the circular reasoning and align the clause with its intended function: to deduct new generation when calculating the net quantity of electricity consumed to determine if the contract constitutes a MLC.

Regulatory statement

Objectives of the proposed amendments

3.45. The objective of the proposed amendments is to provide clarity on how to interpret and apply the MLC provisions of the Code. This is in response to queries received on the interpretation and application of the MLC provisions of the Code.

Evaluation of the costs and benefits of the proposed amendments

3.46. Overall, the Authority considers the benefits of the proposed amendments outweigh the costs. The proposed amendments are expected to deliver net benefits by reducing uncertainty for investors in new generation assets and reducing the costs of complying with the MLC provisions of the Code, while preserving safeguards against inefficient price discrimination.

3.47. In 2021, when the Authority consulted on options to address the risk of inefficient price discrimination occurring in the wholesale electricity market, we evaluated the options using several criteria.[17] We consider the same criteria are applicable when evaluating the costs and benefits of the proposed amendments:

(a) **transparency** – the proposed amendments would result in a more appropriate offset for reflecting the gross new supply resulting from the new plant. This would improve allocative efficiency by reducing a potential barrier to entry for new generation investment.

(b) **confidence** – the proposed amendments would reduce the investor risk premiums for new projects by providing greater certainty around the allowable netting provisions in clause 13.268(4), while having minimal impact on the MLC regime's ability to address instances of inefficient price discrimination.

(c) **incentives to invest in new generation** – the proposed amendments would support new investment by appropriately accounting for the contribution of intermittent new generation to overall supply conditions when determining whether an arrangement qualifies as a MLC.

(d) **supports investment to maintain future reliability** – the proposed amendments would support investment in future reliability by better recognising the generation potential of new assets, particularly where large supply or risk management contracts help mitigate investment risk.

(e) **within the Authority's mandate** – the proposed amendments would improve the effectiveness of the Code by better aligning it with consumers' long-term interests through reducing potential barriers to new investment while still providing consumers with safeguards against inefficient price discrimination.

(f) **aligning with the Government Policy Statement on Electricity** – the proposed amendments are also consistent with the *Government Policy Statement on Electricity*, which sets out the Government's strategic direction and expectations for the electricity sector. The proposed amendments are expected to contribute directly to the following key objectives, as outlined above:

(i) Support investment in renewable generation and infrastructure.

(ii) Promote innovation and efficient market outcomes.

(iii) Protect consumers from excessive prices and inefficient price discrimination.

Evaluation of alternative means of achieving the objectives of the proposed amendments

3.48. This section considers two sets of alternatives: one concerning a different overall approach rather than amending the Code, and the other focused on ensuring effective offsets for intermittent generation.

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17 Refer to Table 3 on page 51 of the Authority's Issues and Options Paper: https://www.ea.govt.nz/documents/2153/Inefficient-Price-Discrimination-in-the-Wholesale-Electricity-Market-Issues-an_zJqQCAI.pdf

First alternative – a different overall approach rather than amending the Code

3.49. The Authority considered issuing guidance without accompanying Code amendments. However, our preference is to amend certain MLC Code provisions and issue guidance to support interpretation and application of these provisions.

Second alternative – ensuring effective offsets for intermittent generation

3.50. Regarding concerns about ensuring effective offsets for intermittent generation, the Authority considered two options to address this, as described in paragraphs 3.26 to 3.44. These options were:

(a) Option 1: Retaining the status quo – ie, leave clause 13.268(4) as is with no further provision for new intermittent generation arising from new investment

(b) Option 2: Amend the Code to recognise intermittent generation arising from new investment.

3.51. We prefer Option 2.

3.52. Table 3 summarises our assessment of alternatives for issuing guidance and offsets for intermittent generation.

Table 3: Assessment of alternatives for issuing guidance and offsets for intermittent generation

Alternative considered	Reason not preferred
Issuing guidance without accompanying Code amendments	We considered that if amendments were not made to the Code, there would be a risk that guidance alone would be insufficient to clarify the key interpretation issues that have arisen. Amending the Code also enables parties who may be affected by these amendments to provide feedback on the MLC Code provisions.
Option 1: Specific focus on providing effective offsets for intermittent generation – retaining the status quo	The status quo does not provide a meaningful offset for new intermittent generation (which can often be near zero in any trading period). Therefore, it does not materially differentiate contractual arrangements which attract new intermittent generation from those that do not.

Assessment of the proposed Code amendments against section 32(1) of the Act

3.53. The Authority considers the proposed amendments are consistent with section 32(1) of the Act because they would provide greater clarity to participants on how to interpret and apply the MLC provisions of the Code. They would support the underlying policy of the MLC provisions of reducing inefficient price discrimination and therefore promoting the efficient operation of the industry.

3.54. The Authority also considers the amendments are consistent with its main statutory objective, to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. These changes would help reduce inefficient price discrimination and therefore promote efficient operation of the industry.

Assessment of the proposed Code amendments against Code amendment principles

3.55. The Authority is satisfied the proposed Code amendments are also consistent with the Code amendment principles. In particular, the proposed Code amendments:

(a) address a problem created by the existing Code requiring amendment

(b) provide an efficiency gain in the electricity industry for the long-term benefit of consumers.

Q3.5. Do you agree the proposed amendments are preferable to the alternative options?

If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

Q3.6. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

4. Improving transparency of hedge disclosure obligations

The existing arrangements

4.1. Participants use risk management contracts to manage spot price risk in the wholesale electricity market. Spot prices fluctuate with changes in demand and supply. This volatility creates uncertainty in cash flow for both generators and retailers. Risk management contracts help participants to manage their costs and revenue by offering an agreed price for electricity over a defined period.

4.2. The over-the-counter (OTC) market for risk management contracts is where buyers negotiate directly with sellers to agree on a price and other terms. These contracts can be customised and provide flexibility for both parties.

4.3. Under subpart 5 of Part 13 of the Code, participants are required to disclose specific details on risk management contracts they enter into in the OTC market. For example price, quantity, grid zone, trade date, and effective date.[18] These requirements apply to all contracts for difference (CfD), fixed price physical supply contracts, and options contracts.

4.4. The Authority publishes risk management contract information in an anonymised form. This enables easy comparison of electricity prices, helps participants analyse their historical contract data, and assists the Authority in evaluating market competitiveness.

Disclosure of power purchase agreements

4.5. A power purchase agreement (PPA) is a CfD or fixed price variable volume contract, where the energy volume sold is directly linked to the output of specific generation plant(s) or station(s). Long-term PPAs are critical for securing financing for new generation projects. A more active and transparent PPA market can support investment in renewable energy, such as solar and wind, by providing revenue certainty for generators and offering buyers or traders an alternative procurement option.

4.6. In late 2024, the Authority broadened the hedge disclosure obligations to require the disclosure of PPAs with the intention of publishing information about PPAs to improve transparency and support more informed negotiations in the OTC market.

4.7. To balance this objective with the need to protect commercially sensitive data, the Authority publishes less detail for PPAs compared to other contract types. Information withheld includes contract start and end dates, price, premium, grid zone, and fuel type.

4.8. This change was part of the Authority's wider efforts to support investment in new generation. By increasing transparency of PPA contracts, it supported other initiatives aimed at improving access to and confidence in PPAs. These include:

(a) investigating barriers to new investment

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[18] Clause 13.219 of the Code.

(b) promoting equal access to hedging products, including PPAs, through non-discrimination obligations

(c) supporting industry-led development of a standardised PPA contract template to simplify negotiations.

4.9. Together, these efforts were designed to make PPAs more accessible and easier to negotiate, particularly for smaller or new market participants. Improved transparency helps reduce information asymmetries, supports more efficient contracting, and builds market confidence. These are all critical to accelerating investment in new generation, enhancing system resilience, and contributing to more competitive electricity prices.

Novel contracts

4.10. The Authority also introduced a new obligation to disclose information in relation to novel contracts.[19] This captures new contract types that fall outside the established categories of risk management contract defined in the Code (CfDs, fixed price physical supply contracts, and options contracts).

4.11. This obligation applies whenever a participant enters into a contract where a substantial purpose is to manage risk for the participant in relation to the spot market for electricity. It requires participants to disclose the key terms of that contract via the hedge disclosure system.

4.12. The purpose of this disclosure requirement is to enable the Authority to identify the prevalence of novel contracts and whether a particular novel contract should be prescribed as a new category of risk management contract.[20] Information about novel contracts is not published on the hedge disclosure system. It is instead used by the Authority to effectively monitor the contracts market in a minimally intrusive way.

Problem definition: transparency of the over-the-counter market for risk management contracts could be improved

4.13. Through the Authority's monitoring of risk management contract disclosure since the changes introduced in 2024, we have identified several ways in which the operation of the hedge disclosure obligations could be improved. This is either through discrete Code amendments or supporting guidance. Each problem is described separately below, alongside the proposal to address the problem.

4.14. Once submissions have been considered, each proposal can progress unchanged, progress with changes, or be withdrawn without affecting the other proposals.

Proposal: improved transparency of over-the-counter market for risk management contracts

4.15. The Authority is proposing to make some discrete Code amendments and changes to guidance. These address operational issues that have been identified following

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19 Refer to clause 13.222A.

20 See discussion in paragraphs 4.26 to 4.33 of the consultation paper: Improving Hedge Disclosure Obligations – Preferred Options.

the reforms to the hedge disclosure obligations introduced in 2024 and will improve transparency and confidence in the market.

4.16. This part of the paper has been structured so each problem and proposal can be independently considered. A regulatory statement is not required for Proposal 5, because these changes are technical and non-controversial (section 39(3)(a) of the Act). A regulatory statement is not required for Proposal 6 and Proposal 7, because these proposals do not involve a Code amendment.

Difficulty disclosing and identifying PPAs

4.17. The Authority's monitoring of risk management contracts, since the requirement to disclose PPAs came into force in October 2024, has shown frequent errors in information submitted. It has also shown an inability to distinguish PPAs from firming agreements. This has required Authority staff to clarify the submission of information with the parties to risk management contracts. This suggests there is some confusion about how to disclose PPAs and firming.

4.18. PPAs are complex contracts. They are difficult to define with certainty because they can take different forms (either as a CfD or a fixed-price variable volume contract). To address these complexities, the Code was drafted to enable identification of PPAs by asking parties to specify whether price in the contract is linked to generation.[21] If yes, the Authority can identify the contract as a PPA.

4.19. The problem is that the relevant instruction in the Code – 'whether price (or prices) in the contract are linked to consumption or generation' – also captures firming contracts.

4.20. This undermines the Authority's ability to easily differentiate between firming contracts and PPAs, resulting in additional follow up with participants to obtain clarity. This impacts on the Authority's ability to monitor the market effectively, and risks reducing the accuracy of analysis conducted on the OTC contracts.

Proposal 1: amend the Code to require disclosure of the generating station

4.21. The Authority proposes to amend clause 13.219(1) of the Code to add a requirement that, if the price (or prices) in the contract are linked to generation, the participant must specify the relevant generating station or stations (or proposed generation project if the generation station is not yet complete). This information would not, however, be published at an individual contract level, to protect commercially sensitive information.

4.22. The *Hedge Disclosure System User Guide for Bulk Upload File Formats* would also be updated to provide guidance on how to submit information for this new field. A response of "not applicable" could be used when the contract is not linked to generation from a particular generating station.

4.23. The purpose of this proposal is to enable the Authority to clearly see what PPAs and firming contracts are being traded and to understand the differences that may occur in contracts of this type.

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[21] Clause 13.219(1)(m).

Q4.1. Do you support the Authority's proposal to require disclosure of the generating station?

Please explain your answer.

Q4.2. Can you identify any other way to more easily identify PPAs and differentiate between these and firming contracts without defining PPAs in the Code?

Disclosure timeframes and other procedural requirements do not apply to novel contracts

4.24. The hedge disclosure requirements set out the information participants must disclose and the timeframes for doing so, depending on the risk management contract type. Options contracts and CfDs must be disclosed within five business days of the trade date, while other risk management contracts must be disclosed within ten business days.[22]

4.25. There is no timeframe for submitting information on novel or "other" contracts that fall outside the established categories of risk management contract defined in the Code.[23] Clause 13.222A outlines the requirement for participants to disclose the key terms of novel contracts via the hedge disclosure system but does not specify a timeframe for making the disclosure. Because novel contracts are not technically defined as risk management contracts under the Code, the standard timeframe obligations do not apply.

4.26. As a result, there is no clear expectation for when participants must submit this information. This creates uncertainty and limits the Authority's ability to access timely data on emerging contract types. Timely disclosure is essential for:

(a) maintaining transparency in the OTC market

(b) supporting effective market monitoring

(c) ensuring all participants have access to relevant information to inform their hedging strategies.

4.27. Some of the procedural requirements for disclosing risk management contracts also do not apply to novel contracts, such as the process for modifying, amending or correcting information submitted, and for verifying information with the other party to the contract. As currently drafted, clause 13.222A requires both parties to the contract (if they are both participants) to separately disclose the key terms of the contract. While this was a deliberate decision given the preference for a minimally intrusive disclosure regime for novel contracts (as discussed above), in practice the different disclosure requirements for novel contracts creates confusion and uncertainty.

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22 Clause 13.225 of the Code.

23 Other contracts are where a substantial purpose of the contract is to manage risk for the participant in relation to the spot market for electricity, but that contract is not a risk management contract as defined in the Code.

Proposal 2: amend the Code to apply similar process requirements for novel contracts

4.28. We propose to amend clause 13.222A to require participants to disclose the required information on novel contracts no later than 5pm, 10 business days after the date the participant entered into the contract. This aligns with the timeframe requirements for submitting information on risk management contracts other than options contracts and CfDs under clause 13.225.

4.29. We also propose to provide for situations where both parties to a novel contract are participants, to avoid duplication in disclosure. Where both parties are participants, only the seller (or the participant listed second alphabetically, if there is no party specified as the seller) would be required to disclose the contract. The same process for submitting modified, amended or corrected information, and for verifying information with the other party to the contract, is proposed to apply to novel contracts, with any necessary modifications.

Q4.3. Do you agree a 10-business day timeframe for submission of information, and the same process requirements as those applying to risk management contracts, should be introduced for novel or other types of contracts?

Please explain your answer.

Difficulty disclosing demand response contracts

4.30. As New Zealand electrifies, demand for electricity will increase. While this increased demand will generally need to be met with new supply, another important element of meeting the increase at lowest cost to consumers will be the effective use of demand-side flexibility.

4.31. Demand response contracts provide a form of demand-side flexibility. Under these contracts, consumers (typically large industrial consumers) receive financial incentives to lower their consumption when demand is high. In doing so, they enable the parties to manage their risk in relation to the wholesale spot market, and provide wider benefits by reducing overall system costs, ultimately benefiting consumers.

4.32. Demand response contracts are not currently treated as a specific type of risk management contract in the Code. Demand response contracts can take different forms. They could be considered an options contract (which is defined as a risk management contract in the Code), or a novel contract (which is disclosed separately under clause 13.222A). Demand response provisions might form a standalone contract or be included within a broader electricity hedge contract.

4.33. The different ways in which demand response contracts could be disclosed in the hedge disclosure system creates confusion and risks different and incomplete information being disclosed. If a demand response contract is disclosed as an options contract, the information in clause 13.219 must be disclosed, but if disclosed as a novel contract, the ‘key terms’ must be disclosed under clause 13.222A.

4.34. Further, some key terms of demand response contracts are not specified in clause 13.219. Specifically, there is no requirement to disclose whether the contract includes demand response provisions and, if so:

(a) the demand response price (the price the consumer is paid to reduce demand on request), or price structure if no price is specified

(b) the minimum and maximum duration of demand response provision

(c) the volume of demand response provision (in MW)

(d) the minimum ‘ramp down’ notice period for exercising a right to engage demand response

(e) whether there are any limits on repeated use of demand response.

4.35. Failure to properly provide for the disclosure of all key terms of demand response contracts reduces transparency in the OTC market and impacts on the Authority’s ability to monitor the market effectively.

Proposal 3: amend the Code to require participants to disclose information on demand response

4.36. The Authority proposes to:

(a) amend the definition of risk management contract to include a demand response contract

(b) amend clause 13.219 to require participants to disclose the key terms of any demand response contract as outlined at paragraph 4.34 above.

4.37. This would ensure that key terms for all demand response contracts are disclosed in the same way. We do not propose publishing this information at a contract level, other than whether the contract includes demand response.

4.38. We propose a different method to collect price information for demand response contracts versus other contracts. In addition to requiring disclosure of the demand response price (the price paid to the consumer for each trading period during which the consumer reduces their consumption), we also propose capturing price structure. Demand response arrangements operate differently than risk management contracts. Some of them will not include a specified price paid for reduced consumption. Instead, the demand response provisions may be linked to the underlying energy hedge price, or to other arrangements between the parties.

4.39. The *Hedge Disclosure System User Guide for Bulk Upload File Formats* would also be updated to provide guidance on how to submit information for demand response contracts.

These proposals would improve transparency, enabling the Authority and market participants to better assess risk, forecast system conditions, and make informed investment and operational decisions.

Q4.4. Do you agree with the proposal to include demand response contracts in the definition of risk management contracts and require disclosure of their key terms (including price and price structure) through the hedge disclosure system?

Please explain your reasons and any impacts you foresee.

Publication of information that could distort hedge disclosure data

4.40. Under clause 13.226A of the Code, the Authority must publish specified information (including trade date and time weighted contract price[24]) in relation to every risk management contract disclosed.[25] There is no exception to this requirement. While the Authority has obligations under clause 13.233 of the Code to keep the information disclosed confidential, this obligation is subject to the overriding requirement to publish the specified information. The Authority must publish this information as soon as possible.

4.41. Publishing information on OTC contracts facilitates the ready comparison of electricity prices and other key terms of risk management contracts and allows all market participants to formulate their own historic contract curves for electricity.[26] This increases transparency in the OTC market, confidence in the price information and, by extension, market competitiveness.

4.42. In some exceptional cases, however, publishing information on some trades could distort the OTC contract information and any price curve developed from that information, undermining the policy intent of the hedge disclosure obligations and reducing confidence in the forward markets.

4.43. For example, this may occur when a risk management contract is transferred to another party, and a back-to-back contract is agreed that mirrors the original contract. Back-to-back contracts will be captured by the hedge disclosure and publication requirements if they meet the definition of risk management contract. However, because back-to-back contracts reflect historical prices, publishing them following our standard process would distort the hedge disclosure data. This is because historical prices would appear under the current trade dates, and existing hedge agreements would effectively be counted twice.

4.44. While this data could be published separately to other hedge information, or with a warning to avoid such distortions, this risks revealing commercially sensitive information. The very small number of back-to-back contracts means the parties to these contracts would likely be apparent (for example, due to public announcements of business acquisitions or mergers).

Proposal 4: amend the Code to provide discretion in making information publicly available

4.45. We propose to amend clause 13.226A to give the Authority discretion to not publish information about a risk management contract if publication of this information would not achieve a purpose specified in clause 13.217 of the Code. This clause sets out the purpose of the hedge disclosure obligations, which is to:

(a) facilitate the ready comparison of electricity prices and other key terms of risk management contracts; and

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24 The time weighted contract price is the price that has been calculated under clause 13.220. It is time weighted, adjusted to a **location factor** for the relevant **grid zone area**, and corrected for **losses**.

25 This information is published here: [Electricity Authority - EMI (market statistics and tools)](#).

26 See clause 13.217 of the Code.

(b) enable persons to formulate their own historic contract curves for electricity; and

(c) provide a more informed basis for the Authority to monitor and assess the market for risk management contracts in respect of electricity, for the purposes of its functions under section 16 of the Act.

4.46. This proposal would ensure that the Authority is not required to publish information if doing so would not facilitate accurate comparison of risk management contracts or the development of accurate contract curves.

Q4.5.	Do you agree this proposal would increase confidence in published price information? If not, why not?

Technical and non-controversial changes

4.47. We have identified two technical issues that would benefit from clarification in the Code. First, the formulas for *time weighted contract price* and *load weighted contract price* are not mathematically correct as it is not clear that LF[27] x LAF[28] together form the divisor. A technical change is needed to group these terms for the correct order of operation.

4.48. Second, the wording of subclauses 13.226A(1) and (2) is unclear as to the publication of information about PPAs. The policy intent of these clauses is that the Authority will *only* publish the information specified in subclause (2) for PPAs, not the wider set of information for other risk management contracts specified in subclause (1).[29] While subclause (1) states that this is 'subject to subclause (2),' it is not clear that, when subclause (2) applies, subclause (1) does not apply. Subclause (2) also uses the word 'may' not 'must', which does not align with subclause (1) or reflect the policy intent of this clause.

Proposal 5: amend the Code to correct the contract price formulas and clarify disclosure requirements for PPAs

4.49. The Authority proposes to amend the formulas for calculating the time weighted contact price in clause 13.220(2) and the load weighted contract price in clause 13.220(3). The current and updated (proposed) formulas are displayed below:

27 LF is defined in the Code as the location factor, for the relevant node at which the price is set in the contract, as published by the WITS manager in accordance with clause 13.221.

28 LAF is defined in the Code as a loss adjustment factor, which is: (a) if the time weighted contract price for the contract is referenced to a point of connection on the grid, 1; or (b) for all other contracts, 0.937 (being the difference between 1 and the loss factor of 0.063).

29 See: Improving Hedge Disclosure Obligations - Decision Paper at paragraph 3.81.

13.220(2) Current:

$$CP_{\underline{tw}} = \left\{ \frac{\sum_{i=1}^{n} P_i \text{ x } TP_i}{\sum_{i=1}^{n} TP_i} \right\} / \text{LF x LAF}$$

Updated:

$$CP_{tw} = \frac{\left\{ \frac{\sum_{i=1}^{n} P_i \times TP_i}{\sum_{i=1}^{n} TP_i} \right\}}{LF \times LAF}$$

13.220(3) Current:

$$CP_{lw} = \left\{ \frac{\sum_{i=1}^{n} P_i \text{ x } V_i}{\sum_{i=1}^{n} V_i} \right\} / \text{LF x LAF}$$

Updated:

$$CP_{lw} = \frac{\left\{ \frac{\sum_{i=1}^{n} P_i \times V_i}{\sum_{i=1}^{n} V_i} \right\}}{LF \times LAF}$$

4.50. The Authority also proposes to make a technical change to clarify the relationship between subclauses 13.226A(1) and (2) and more clearly reflect the policy intent.

Specification of the trade date

4.51. The trade date for the purpose of subpart 5 of Part 13 means the date the parties enter into a risk management contract. This is important because the timeframes for submitting information in clause 13.225 depend on the trade date. Parties must submit information either 5 business days after the trade date (for CfD and options), or 10 business days after the trade date (for any other type of risk management contract and novel contracts if the Code is amended for proposal 2).

4.52. There have been inconsistent views about the reporting of trade dates among parties required to submit information. Some believe the trade date is the date the parties verbally agree to enter into a contract, others believe it is the date that the contract is signed.

Proposal 6: Provide guidance on reporting of trade date

4.53. We propose to provide guidance to the parties required to submit information. The parties to risk management contracts who are required to submit the information specified in clauses 13.219 and 13.223 should agree on how the trade date is reported at the time of agreeing to the contract. Adopting this proposal would result in the frequently asked questions published on the Electricity Hedge Disclosure System website being updated.[30]

Additional choices for option style disclosure and nodes

4.54. Under clause 13.219, participants are required to disclose the node at which each price is set for each trading period. However, some contracts relate to nodes that are not yet determined and will become known when the contract takes effect. For example, this is common in PPAs for new renewable generation projects, where the node is confirmed once the generation asset is commissioned.

4.55. Under the existing clause, participants are also required to disclose the option style for option contracts, with the hedge disclosure system offering three choices: American, Asian or NA (not applicable). However, some option contracts traded in New Zealand use the European style, which is not currently captured.

Proposal 7: Add more choice to option style

4.56. To address these two problems, we propose adding 'unknown' as an additional choice in the node field and adding 'European' as an additional choice in the related field in the hedge disclosure system. This proposal will update the File Upload User Guide[31] on the Electricity Hedge Disclosure System website.

Regulatory statement[32]

Objectives of the proposed amendment

4.57. The objective of the proposed amendment is to ensure a robust set of hedge disclosure obligations which will:

(a) increase transparency in the OTC market, facilitating effective risk management

(b) enhance confidence in market competitiveness

(c) strengthen regulatory oversight, by enhancing the Authority's market facilitation, monitoring and enforcement functions and supporting future policy development.

Evaluation of the costs and benefits of the proposed amendment

4.58. The Authority considers that making the proposed amendments would be of net benefit to consumers.

Benefits

4.59. The primary benefit of this proposal is to improve hedge disclosure data through:

(a) clearer identification of PPAs and firming contracts

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30 https://www.electricitycontract.co.nz/

31 Upload_File_Format.pdf

32 This regulatory statement applies to proposals 1 to 3 (see paragraph 4.14 above).

(b) more timely disclosure of novel contracts and clearer processes for updating and verifying this information

(c) more consistent information on demand response arrangements

(d) measures to protect against distortions in the published data.

4.60. This would better achieve the purpose of the hedge disclosure obligations, which is to:[33]

(a) facilitate the ready comparison of electricity prices and other key terms of risk management contracts; and

(b) enable persons to formulate their own historic contract curves for electricity; and

(c) provide a more informed basis for the Authority to monitor and assess the market for risk management contracts in respect of electricity, for the purposes of its functions under section 16 of the Act.

4.61. Efficient hedging strategies put downward pressure on retail costs and prices. Moreover, the ability to hedge against spot price volatility based on prices that are visible to all market participants helps to reduce entry barriers and enhances competition in the electricity market.

4.62. Better information also strengthens participants' negotiating position. When accurate and timely price signals are available, buyers and sellers can negotiate fairer and more competitive terms. This transparency lowers transaction costs, improves liquidity, and makes PPAs more accessible—particularly for smaller participants or new entrants who often face barriers to securing long-term contracts.

4.63. These proposals are incremental improvements to transparency and accuracy of information on PPAs which can promote efficient investment in generation and energy storage.

Monitoring the OTC market

4.64. Increasing the Authority's access to information on the OTC market is crucial for effective regulatory oversight of the electricity industry. It enhances the Authority's ability to perform its monitoring functions to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The increased access to information enables the Authority to identify and respond to emerging issues to support market development, further increasing confidence in the market.

4.65. With more information on the OTC market, the Authority will be able to assess market competitiveness, structural support for price stability, and fair competition. It will also allow continuous monitoring of factors driving price volatility and market liquidity levels. This comprehensive understanding empowers the Authority to formulate policies that align with the dynamic electricity market, reducing the need for unnecessary corrective interventions.

[33] Clause 13.217 of the Code.

Costs – parties required to submit information

4.66. The proposed changes to the hedge disclosure obligations have relatively low costs since they represent only minor, incremental changes to the existing hedge disclosure obligations. Table 4 shows the Authority's assessment of the costs for parties required to disclosure information.

Table 4: Assessment of costs

Proposal		Costs for parties required to disclose information	Assessment of cost
1	Amend the Code to require disclosure of the generating station.	Additional information would need to be disclosed when the disclosing party makes their disclosure.	Low
2	Amend the Code to apply similar process requirements for novel contracts.	New deadline of ten business days, comparable with risk management contracts. New requirement to keep information up-to-date (reporting modifications, also comparable with risk management contracts). The requirement on both parties to make the disclosure would be replaced with a verification process for the second party, meaning this is unlikely to increase net costs (and may in fact reduce costs for that party).	Low
3	Amend the Code to require participants to disclose information on demand response.	Additional information needs to be disclosed when the contract includes a demand response element.	Low
4	Amend the Code to provide discretion in making information publicly available.	None.	-

4.67. All active participants in the contracts market already have policies in place to disclose their risk management information under the Code.

4.68. Proposal 1 aims to improve disclosure by requiring additional information in relation to PPAs. While this change increases compliance requirements, we do not anticipate the additional data demands to be technically burdensome and expect these to result in minimal additional costs for participants.

4.69. Proposal 2 adds a deadline of ten business days to provide the information required on novel contracts under clause 13.226A and applies existing process requirements to novel contracts. This reflects current practice for risk management contracts. We think any additional costs incurred will be minimal.

4.70. Proposal 3 includes capturing price structure in addition to requiring disclosure of the demand response price (the price paid to the consumer for each trading period during which the consumer reduces their consumption). As with proposal 1, this change increases compliance requirements, but we expect these impose minimal additional costs for participants.

4.71. Proposal 4 does not change participants' disclosure obligations. It only changes the way the Authority may publish the information. Therefore, adopting the proposal would not impose any costs on parties required to disclosure information.

Evaluation of alternative means of achieving the objectives of the proposed amendment

Alternative considered	Reason not preferred
The Authority has not identified any alternatives to achieve the objective.	N/A

Assessment of the proposed Code amendment against section 32(1) of the Act

4.72. The Authority considers the proposed Code amendment is consistent with section 32(1) of the Act because it is necessary or desirable to promote, for the long-term benefit of consumers:

(a) **competition in the electricity industry**: increases robustness of hedge disclosure data, which will enable market participants to more effectively manage their exposure to price volatility and facilitate the entry of new participants.

(b) **the efficient operation of the electricity industry**: more robust data would lead to more efficient price discovery and allocation of resources.

(c) **the performance by the Authority of its functions**: enhances the Authority's ability to perform its market monitoring, market facilitation and enforcement functions under the Act, because it would enable the Authority to collect more timely information about the operation of the OTC contracts market and monitor market competitiveness.

Assessment of the proposed Code amendment against Code amendment principles

4.73. The Authority is satisfied the proposed Code amendments are consistent with the Code amendment principles. In particular, the proposed Code amendment:

(a) addresses a problem created by the existing Code requiring an amendment

(b) provides an efficiency gain in the electricity industry for the long-term benefit of consumers.

Q4.6. Do you agree the proposed amendment is preferable to the alternative options?

If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

Q4.7. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

5. Technical and non-controversial Code amendments

5.1. The Authority proposes to correct a list of minor typographical and other errors in the Code. These errors include outdated cross-references and formulas, incorrectly bolded terms, and other minor drafting errors.

5.2. None of the proposed amendments are intended to alter the meaning of the Code. These amendments are considered technical and non-controversial under section 39(3)(a) of the Act. The Authority is required to publicise a draft of the proposed technical and non-controversial changes, but is not required to prepare a regulatory statement or consult on the proposed amendments.

5.3. Appendix D is a table of proposed changes that the Authority is satisfied are technical and non-controversial. Although the Authority is not required to consult on the proposed changes, we invite comment on these proposals.

Appendix A Proposed Code amendment: Minimum offer price exclusions for tie-breaker situations

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. Text is shown in ~~red strikethrough~~ if it is to be deleted from the Code.

Part 13 Trading Arrangements

13.15 How price is to be specified in bids or offers

(1) Prices in **bids** or **offers** must be expressed in dollars and whole cents per **MWh** excluding any **GST**. There is no upper limit on the prices that may be specified and the lower limit is $0.00/**MWh**, subject to subclause (2) and clauses 13.9(d), 13.24, 13.26, and 13.116.

(2) The lowest price that may be specified in an **offer** for an **intermittent generating station** is $0.01/**MWh**.

13.26 Exception for embedded generation

An **embedded generator** required to submit an **offer** in accordance with clause 8.25(5) for a **generating station** that is not an **intermittent generating station** may make an **offer** at a 0 price and clause 13.116(2) applies to the **embedded generator**.

13.116 Offers at 0

(1) Subject to subclause (2), a **generator** may offer **electricity** to the **clearing manager** at a 0 price only if the **generator** has an authorisation from an **auction** in accordance with clauses 13.108 to 13.115.

(2) A **generator** may offer **electricity** to the **clearing manager** at a 0 price without an authorisation from an **auction** only in relation to—

- (a) generating **plant** that comes within the scope of clauses 13.24 or 13.26; or
- (b) **offers** for a **generating station** that is not an **intermittent generating station** submitted before publication of **auction** results, but, if authorisation from an **auction** is not granted, such **offers** are cancelled or revised so that they no longer contain a 0 price before 1300 hours on the day before the **trading day** for which the **offers** apply.

13.107A Intermittent generators may not bid

An **intermittent generator** may not bid for **auction rights**. In this subpart, all references to a **generator** exclude **intermittent generators**.

Appendix B Proposed Code amendment: Materially large contracts

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

B.2. Text or formatting is <u>red underlined</u> if it is to be added to the Code. Text is shown in ~~red strikethrough~~ if it is to be deleted from the Code.

Electricity Industry Participation Code 2010

Part 13

Trading arrangements

13.268 Definition of materially large contract

(1) A **materially large contract** is—

(a) a contract that—

(i) is not entered into through a derivatives exchange; and

<u>(ia) results in a final price paid by the **buyer** (after accounting for any discounts) of less than:</u>

<u>(A) the price of an equivalent exchange traded derivative or derivatives; or</u>

<u>(B) the spot price, for any trading period during the term of the contract; and</u>

(ii) includes terms under which the **buyer** itself will consume **electricity**; and

(iii) relates to a net quantity of **electricity** that equals or exceeds 150 **MW** consumed at a point in time; or

(b) two or more contracts where:

(i) all the contracts satisfy paragraph (a)(i) <u>and (ia);</u> and

(ii) at least one contract satisfies paragraph (a)(ii); and

(iii) the contracts when taken together satisfy paragraph (a)(iii) and meet one of the descriptions set out in paragraph (c) below:

(c) the descriptions referred to at paragraph (b)(iii) above are:

(i) two or more contracts between a **generator** and a **buyer**; or

(ii) at least one contract between a **generator** and a **buyer** and at least one contract between that **generator** or its related company and that **buyer** or its related company; or

(iii) at least one contract between a **generator** and a **buyer** and at least one contract involving a second **generator** and the same **buyer** where the contracts rely on each other or are otherwise interdependent; or

(iv) at least one contract between a **generator** and a **buyer** and at least one contract between the same **generator** and a second **generator** where the contracts rely on each other or are otherwise interdependent; or

(v) any other arrangement that is substantially of the same kind as that described in any of subparagraphs (i)-(iv).

(2) For **materially large contracts** made up of two or more different **generators'** contracts, any reference to **materially large contract** in the following clauses must be read as only referring to an individual **generator's** contract(s) that forms part of a **materially large contract**, rather than as a reference to the multiple **generators'** contracts.

(3) Where a **materially large contract** allows for the possibility of varying quantities of **electricity** consumption at any one time, the maximum quantity of **electricity** consumption possible under the contract at any one time is to be used for the purpose of determining whether the **MW** threshold in subclause (1)(a)(iii) is met.

(4) For the purpose of subclause (1)(a)(iii), the net quantity of **electricity** is the ~~total~~ **MW** consumed at a point in time (calculated in accordance with subclause (3)) less any **MW** generated from new generation (calculated in accordance with subclause (5)), where the ~~**materially large contract**~~ contract is material to the **generator's** decision to invest in the new generation.

(5) For the purposes of subclause (4), **MW** generated from new generation is:

(a) the median **MW** expected to be generated by the new **generating station** in any **trading period** over the contract period following its **commissioning**, to be calculated using relevant industry standards for resource assessment data and accounting for all relevant factors reasonably expected to affect the new **generating station**'s contribution to the **grid**, including (without limitation and to the extent applicable) —

(i) the efficiency of the new **generating station**:

(ii) degradation of the **generating station**'s performance over time:

(iii) the **generating station**'s operational availability:

(iv) fuel supply and quality:

(v) the impact of climate oscillations such as the El Niño-Southern Oscillation, Southern Annular Mode, or other relevant climate variability modes; or

(b) to be calculated using an alternative methodology which is robust and supported by evidence that meets or exceeds industry standards for the appropriate resource assessment.

(~~5~~ 6) For the purpose of this subpart, related company has the meaning set out in section 2(3) of the Companies Act 1993.

Appendix C Proposed Code amendment: Refining hedge disclosure obligations to increase transparency

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

C.2. Text or formatting is red underlined if it is to be added to the Code. Text is shown in ~~red strikethrough~~ if it is to be deleted from the Code.

Part 1 – Interpretation

buyer, for the purposes of subpart 5 and subpart 7 of Part 13, means—

(a) in respect of a **contract for differences**, the fixed-price payer, being the **party** obliged to make payments at a fixed price from time to time during the **term** of the contract; or

(b) in respect of a **fixed-price physical supply contract** or a **demand response contract**, the purchaser of **electricity**; or

(c) in respect of an **options contract** either—

  (i) the **party** paying the **premium**; or

  (ii) if there is no **premium**, the **party** who agrees to be the **buyer** for the purposes of subpart 5 or subpart 7 (as applicable) of Part 13; or

  (iii) if neither **party** agrees to be the **buyer**, the **party** whose name is the first alphabetically; or

(ca) for the purposes of subpart 5 of Part 13, in respect of a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract**, either—

  (i) the **party** specified as the buyer in the contract; or

  (ii) if neither **party** is specified as the buyer, the **party** whose name is the first alphabetically; or

(d) for the purposes of subpart 7 of Part 13, in respect of any other contract, the **party** consuming the **electricity** that the contract relates to

demand response contract means a contract containing the right to reduce the consumption of **electricity** by an amount that equals or exceeds 0.1 **MW** of **electricity**

demand response premium, in relation to a **demand response contract**, means the dollar amount paid by the **seller** to the **buyer**

demand response price means the price paid to the **consumer** for each **trading period** during which the **consumer** reduces their consumption of **electricity** under a **demand response contract**

…

risk management contract, for the purposes of subpart 5 and subpart 7 of Part 13, means—

(a) a **contract for differences**; or

(b) a **fixed-price physical supply contract**; or

(c) an **options contract**; or

(caa) for the purposes of subpart 5 of Part 13, a **demand response contract**; or

(ca) for the purposes of subpart 5 of Part 13, a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract**; but

(d) does not include an **FTR**

seller, for the purposes of subpart 5 and subpart 7 of Part 13, means—

(a) in respect of a **contract for differences**, the **floating-price payer**; or

(b) in respect of a **fixed-price physical supply contract** or a **demand response contract**, the **party** selling the **electricity**; or

(c) in respect of an **options contract**, either—

(i) the **party** receiving the **premium**; or

(ii) if there is no **premium** under the **options contract**, the **party** who agrees to be the **seller** for the purposes of subpart 5 or subpart 7 (as applicable) of Part 13; or

(iii) if neither **party** agrees to be the **seller**, the **party** whose name is the second alphabetically; or

(ca) for the purposes of subpart 5 of Part 13, in respect of a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract**, either—

(i) the **party** specified as the seller in the contract; or

(ii) if neither **party** is specified as the seller, the **party** whose name is the second alphabetically; or

(d) for the purposes of subpart 7 of Part 13, in respect of any other contract, the **party** who is not the **buyer**

Part 13 – Trading arrangements

Subpart 5 – Hedge arrangement disclosure

13.219 Information that must be submitted

(1) The party specified in clause 13.218 must submit the following information to the **approved system** in relation to every **risk management contract**, excluding exchange-traded **risk management contracts** where the **parties** have provided consent under clause 13.236AA:

(a) each **party's** legal name:

(b) each **party's** email address for notice:

(c) the **trade date**:

(d) the **effective date**:

(e) the **end date**:

(f) the **quantity**:

(g) whether the contract is a **contract for differences**, a **fixed-price physical supply contract**, an **options contract** or, if the contract is a type of **risk management contract** prescribed by the **Authority** under clause 13.219B, the type of **risk management contract**:

(ga) whether the contract is or includes a **demand response contract**:

(gb) if the contract is or includes a **demand response contract**—
   (i) the **demand response price**, if specified in the contract:
   (ii) if no **demand response price** is specified, whether consideration for exercising a right to demand response in the contract is linked to:
      (A) price(s) in the contract referred to in subclause (l); or
      (B) other agreements between the parties (in which case, this must be specified):
   (iii) the minimum and maximum duration of demand response provision under the contract:
   (iv) the specified volume of **electricity** by which consumption may be reduced:
   (iii) the minimum notice period prior to exercising a right to demand response:
   (iv) the limits, if specified, on repeated use of the demand response provisions:
   (v) the **demand response premium**, if specified in the contract:

(h) if the contract is an **options contract**—
   (i) whether it is a call option or a put option; and
   (ii) if it is a call option, whether the **buyer** has the right to buy less than the **quantity**; and
   (iii) whether it is a cap option or floor option; and
   (iv) the option style (for example, American or Asian):

(i) the fuel type (for example, solar, wind, thermal, or hydro), if specified in the contract:

(j) the **premium**, if specified in the contract:

(k) the **trading periods** during which each price in the contract applies:

(l) in relation to each **trading period** during which a price (other than **demand response price**) in the contract applies—
   (i) the **node** at which each price is set; and
   (ii) the price or series of prices to be paid at each relevant **node**; and
   (iii) if applicable, the specified volume of electricity for each price to be paid at each relevant **node**:

(m) whether price (or prices) in the contract are linked to consumption or generation of **electricity**:

(ma) if the price (or prices) in the contract is linked to generation of **electricity**, the **generating station** or **generating stations**, or the proposed generation project, the contract is linked to:

(n) whether there is an **adjustment clause**:

(o) whether there is a **force majeure clause**:

(p) whether there is a **special credit clause**:

(q) whether there is a **suspension** clause:

(r) whether there are any other clauses providing for the pass-through of certain costs, levies or tax or some form of carbon-related cost:

(s) whether the contract uses any version of the International Swaps and Derivatives Association Master Agreement (ISDA Master Agreement) (including where the schedule to the form of the ISDA Master Agreement used for the contract makes an amendment to the main part of the ISDA Master Agreement):

(t) any other information specified in a notice **published** by the **Authority** under clause 13.219A.

(2) The party specified in clause 13.218 must submit the information required by this clause in the form specified by the **Authority** and in accordance with clause 13.225(1).

13.220 Calculation of contract prices

…

(2) The **time weighted contract price** is to be calculated in accordance with the following formula:

$$CP_{tw} = \left\{ \frac{\sum_{i=1}^{n} P_i \times TP_i}{\sum_{i=1}^{n} TP_i} \right\} / (LF \times LAF)$$

…

(3) The **load weighted contract price** is to be calculated in accordance with the following formula:

$$CP_{lw} = \left\{ \frac{\sum_{i=1}^{n} P_i \times V_i}{\sum_{i=1}^{n} V_i} \right\} / (LF \times LAF)$$

…

13.222A Information about other contracts that must be submitted

(1) If a **participant** enters into a contract where a substantial purpose is to manage risk for the **participant** in relation to the spot market for **electricity**, but that contract is not a **risk management contract**, the **participant** must submit to the **approved system**:

(a) notification that the **participant** has entered into the contract; and

(b) a description of the key terms of the contract.

(2) The information specified in subclause (1) must be submitted to the **approved system** no later than 5pm, 10 **business days** after the date the **participant** entered into the contract.

(3) If both parties to the contract are **participants**, the obligation in subclause (1) only applies to:

(a) the **participant** specified as the seller in the contract; or

(b) if neither party is specified as the seller, the person whose name is second alphabetically.

(4) Clauses 13.223, 13.224, 13.227 and 13.227A apply with all necessary modifications as if the contract were a **risk management contract**.

…

13.226A Authority must make certain information publicly available

(1) Unless ~~Subject to~~ subclause (2) applies, the **Authority** must, as soon as practicable after the **WITS manager** makes information available to the **Authority** under clause 13.226(1), **publish** the following information in relation to every **risk management contract**:

- (a) information submitted under clauses 13.219(1)(c) to 13.219(1)(ga), 13.219(1)(h), 13.219(1)(j), ~~and~~ 13.219(1)(m), and 13.219(n) to 13.219(1)(s):
- (b) information made available under clauses 13.226(1)(b) to (e):
- (c) where any information is submitted under clauses 13.223(1) and 13.224, —
  - (i) that information, to the extent that it modifies, amends, or corrects information **published** under paragraph (a); and
  - (ii) any necessary amendment to the information **published** under paragraph (b).

(2) If the **risk management contract** is for the purchase of **electricity** linked to **generation** at a particular **generating plant** or **generating plants**, or **generating station** or **generating stations**, the **Authority** must ~~may also~~ **publish** the following information in relation to the **risk management contract**:

- (a) information submitted under clauses 13.219(1)(c), 13.219(1)(f) to 13.219(1)(ga), 13.219(1)(h), ~~and~~ 13.219(1)(m), and 13.219(n) to 13.219(1)(s):
- (b) information made available under clause 13.226(1)(b):
- (c) where any information is submitted under clauses 13.223(1) and 13.224,—
  - (i) that information, to the extent that it modifies, amends, or corrects information **published** under paragraph (a); and
  - (ii) any necessary amendment to the information **published** under paragraph (b).

(2A) The **Authority** is not required to **publish** information under subclause (1) or (2) if **publication** would not achieve a purpose specified in clause 13.217.

(3) When information submitted under clause 13.219 or 13.223(1) is first **published** under subclause (1) or (2), the **Authority** must indicate that the information is unverified.

(4) The **Authority** must, as soon as practicable, update the indication made under subclause (3) to verified, pending verification, not disputed, disputed or subject to a long-term dispute every time the **WITS manager** notifies the **Authority** of a change in accordance with clauses 13.227(1) to (3), 13.227(4) and 13.227A(4).

Appendix D Proposed Code amendments: Technical and non-controversial

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

D.2. Text or formatting is red underlined if it is to be added to the Code. Text is shown in ~~red strikethrough~~ if it is to be deleted from the Code.

#	Clause	Issue	Proposed amendment
PART 1 – PRELIMINARY PROVISIONS			
1.	1.1(1) – definition of **bank**	Name of legislation was amended in 2022	**bank** means a registered bank within the meaning of the ~~Reserve Bank of New Zealand Act 1989~~ Banking (Prudential Supervision Act) 1989 that is carrying on in New Zealand the business of banking
2.	1.1(1) – definition of **bona fide physical reason**	The words **asset** and **assets** should be in bold as this is a defined term	**bona fide physical reason** includes,— … (ba) in relation to an **intermittent generator**, a situation in which the **intermittent generator** reduces the output of an **intermittent generating station**— … (iv) in anticipation of the expected onset of a weather event that would be likely to cause the **intermittent generating station's** **asset** protection systems to shut down **assets** forming part of the **intermittent generating station**; and …
3.	1.1(1) – definition of **capacity reserve**	Definition no longer required nor used	~~**capacity reserve** means—~~ ~~(a) demand that can be decreased for the purpose of adjusting a **constraint**; or~~ ~~(b) generation that can be increased or decreased for the purpose of adjusting a **constraint**~~ *[Revoked]*
4.	1.1(1) – definition of **designated transmission customers**	Definition should refer to singular rather than plural to reflect standard Code drafting practice. This does not change the application of the Code, because words in the singular include the plural, and vice versa, under section 19 of the Legislation Act 2019.	**designated transmission customer** means a **participant** who is required to enter into a **transmission agreement** with **Transpower** under subpart 2 of Part 12 **designated transmission customers** ~~means **participants** who are required to enter into **transmission agreements** with **Transpower** under subpart 2 of Part 12~~ *[Revoked]*
5.	1.1(1) – definition of **distribution network capacity**	The word generation is not defined and should not be bolded	**distribution network capacity** means the capacity of a **distribution network** to convey **electricity** under a range of load and generation conditions in accordance with **reasonable and prudent operating practice**

#	Clause	Issue	Proposed amendment
6.	1.1(1) – definition of **financial year**	The defined term should not be in bold within its own definition	**financial year** means, except in Part 6A and Schedule 12.4, the financial year adopted by a **participant** from time to time, being a 12 month period as a **participant** determines
7.	1.1(1) – definition of **forecast reserve prices**	Missing word	**forecast reserve prices** means the prices for **fast instantaneous** **reserve** and **sustained instantaneous reserve** for each **island** scheduled in the **price-responsive schedule** or the **non-response schedule** (whichever is relevant) in dollars and cents
8.	1.1(1) – definition of **incremental costs**	Unnecessary full stop at end of definition	**incremental costs**, for the purpose of Part 6, means: … (b) the **distribution** costs … that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**~~.~~
9.	1.1(1) – definition of **interconnection asset**	Reference to subpart 2 of Part 12 is no longer necessary	**interconnection asset**, for the purposes of subparts ~~2,~~ 6 and 7 of Part 12— (a) has the meaning set out in the **transmission pricing methodology**; and (b) includes the **HVDC link**
10.	1.1(1) – definition of **net purchase quantity assessment**	"Principal performance objectives" should be "principal performance obligation" which is a defined term	**net purchase quantity assessment** means the quantity of an **ancillary service** derived from the following formula: a = b – c where … b is the gross amount of an **ancillary service** that the **system operator** believes is required in order to meet the **principal performance** ~~**objectives**~~ **obligation**; …
11.	1.1(1) – definition of **node**	The word "transformer" is not a defined term so should not be in bold	**node** means— … (b) a location at which an electrical link that is not part of or does not contain a transformer, diverges or terminates (such as a "tee" point or a deviation); or …
12.	1.1(1) – definition of **notified planned outage**	The words "Technical Code" should be in bold as they are a defined term	**notified planned outage**, for the purposes of **Technical Code** D of Schedule 8.3, means any **planned outage** for which the **asset owner** has given notice to the **system operator** in accordance with **Technical Code** D of Schedule 8.3
13.	1.1(1) – definition of **outage**	The words "Technical Code" should be in bold as they are a defined term	**outage**— (a) for the purposes of **Technical Code** D of Schedule 8.3,,,
14.	1.1(1) – definition of **planned outage**	The words "Technical Code" should be in bold as they are a defined term	**planned outage**— (a) for the purposes of **Technical Code** D of Schedule 8.3,,,
15.	1.1(1) – definition of **scaling factor**	The words "Technical Code" should be in bold as they are a defined term	**scaling factor,** for the purpose of Appendix A of **Technical Code** C of Schedule 8.3,

#	Clause	Issue	Proposed amendment
16.	1.1(1) – definition of **specified person**	Legislative reference needs to be updated following the Regulatory Systems (Economic Development) Amendment Act 2025	**specified person** has the meaning given in section ~~32(6)~~ 5 of the **Act**
17.	1.1(1) – definition of **un-modelled transmission asset**	The words "transmission asset" are not a defined term so should not be in bold. Asset is however a defined term on its own.	**un-modelled transmission asset** means a transmission **asset** for which the **system operator's dispatch** optimisation model does not include **asset** ratings as a **constraint**
18.	1.1(1) – definition of **unplanned outage**	The words "Technical Code" should be in bold as they are a defined term	**unplanned outage**— (a) for the purposes of **Technical Code** D of Schedule 8.3,,,
		PART 2 – AVAILABILITY OF INFORMATION	
19.	2.19(2) - Factors the Authority must consider before publishing notice	Full stop at the end of clause should not be in bold.	(2) Before **publishing** a notice under clause 2.16, the **Authority** must consider the impact of the proposed information requirements on each **participant** to whom it is proposed the notice apply.
20.	2.21 - Participants may identify confidential information	The clause does not need to be numbered as subclause (1) when there is no subclause (2).	~~(1)~~ In supplying information under clause 2.20, a **participant** may identify any information for which confidentiality is sought by reason that— (a) disclosure of the information would unreasonably prejudice the commercial position of the **participant** or the person who is the subject of that information; or …
21.	2.22(5)(c) - Authority dealing with information identified as confidential	The defined term "participant" is not fully in bold.	(5) Subclause (4) does not prevent the **Authority** from— … (c) disclosing the information where the **participant** who supplied the information or the person who is the subject of the information (if different from the **participant**) either: …
		PART 6A – SEPARATION OF DISTRIBUTION FROM CERTAIN GENERATION AND RETAILING	
22.	6A.1(2)(a)(i), 6A.1(2)(ii), 6A.3(3)(a), 6A.4(3)(a), and Schedule 6A.1 clause 3I(1)(a)	MW is a defined term and should be in bold.	… **MW** …

#	Clause	Issue	Proposed amendment
23.	Schedule 6A.1 clause 1(2)	The words "arm's length" should not be in bold as it is not a defined term.	(2) Without limiting the ordinary meaning of the expression, arm's-length includes having relationships, dealings, and transactions that…
24.	Schedule 6A.1 clause 2(2)	The word "interested" should not be in bold as it is not a defined term.	(2) In this schedule, a person is interested in a transaction if the person, or an associate of that person,— …
PART 7 – SYSTEM OPERATOR			
25.	7.16(2)(a) – Authority must consent to consultation before system operator consults on proposal to amend system operation document	The word "Code" should not be in bold as it is not a defined term.	(2) The purpose for the **Authority** consenting to consultation is to enable the **Authority** to identify to the **system operator** any issues with— (a) the proposal that may cause the **Authority** to not issue a notice to adopt the amendment under section 131B(2) of the **Act** or to not progress the amendment as a Code amendment under section 38 of the **Act**, as the case may be; …
26.	7.16(3)	"System operator" is a defined term and should be in bold.	(3) When requesting the **Authority's** consent, the **system operator** must provide the following information to the **Authority**: (a) the consultation information in clause 7.20(2)(a): …
27.	7.21(3)(a)	The word "Code" should not be in bold as it is not a defined term.	(3) The approval by the **Authority** of proposed amendments to a **system operation document**— (a) does not remove the requirement for the **Authority** to comply with either section 38 or section 131B of the **Act** in order to give legal effect to the amendments as part of the Code; and …
PART 8 – COMMON QUALITY			
28.	8.5(1)(a) – Restoration	The word "generation" should not be in bold as it is not a defined term in the Code.	(1) If an event disrupts the **system operator's** ability to comply with the **principal performance obligations**, the **system operator** must re-establish normal operation of the power system as soon as possible, given— (a) the capability of generation, and **ancillary services**; and …
29.	8.31(1) – Grant of dispensations	The first two variables should not be in bold. Final closing bracket in variable Q_{GENxt} should not be in bold. The formula format has been updated for consistency	(1) Subject to subclause (1A), the **system operator** must … (c) if the **dispensation** is a **generating unit dispensation** from clause 8.19(1) or (3), the **generator** must be allocated the following costs in a relevant **trading period** with respect to paragraph (a) for each of **fast instantaneous reserves** or **sustained instantaneous reserves**: $DispCost_{GENxt} = 0.5 \underline{\times} \cancel{*} Q_{GENxt} \underline{\times} \cancel{*} P_{IRt}$ Where

#	Clause	Issue	Proposed amendment
		across the Code and to reflect modern usage.	DispCost$_{GENxt}$ is the cost payable by a **generator** for **generating unit** x in any **trading period** t in which a class of **instantaneous reserves** is procured as a direct result of that **generating unit's dispensation** to ensure that the frequency does not fall below 47 Hertz or, in the South Island, below the **minimum South Island frequency** Q$_{GENxt}$ is the **MW** amount by which **generating unit** x is unable to sustain pre-event output in **trading period** t with reference to clause 8.19(1) or (3) (as the case may be) as determined from the capabilities specified in that **generating unit's dispensation** (different amounts may be specified with respect to each class of **instantaneous reserves**)
30.	8.35(1)(d) – Revocation of equivalence arrangement and revocation or variation of dispensation	The word "provided" should not be in bold as it is not a defined term.	(1) The **system operator** may revoke approval of an **equivalence arrangement** or revoke or vary the grant of a **dispensation** as the **system operator** reasonably considers appropriate if, at any time after the **system operator** has approved an **equivalence arrangement** or granted a **dispensation**, the **system operator** is satisfied that 1 or more of the following apply: … (d) withdrawal is provided for under the terms of the **dispensation** granted: …
31.	8.43(a)(iv) – Content of procurement plan	The word "services" should be "service" singular because "alternative ancillary service arrangement" is the defined term.	A **procurement plan** must, for each **ancillary service—** (a) specify the principles that the **system operator** must apply in making a **net purchase quantity assessment**, which must include— … (iv) assessing the impact that **dispensations** and **alternative ancillary** ~~**services**~~ **service** **arrangements** held by **asset owners** will have on the quantity of **ancillary services** required to enable the **system operator** to comply with the **principal performance obligations**; and …
32.	8.58 – Frequency keeping costs are allocated to purchasers	The words "kWh" and "x" in the variable Offtake$_{PURxt}$ should not be in bold as they are not defined terms. The word "alternative" in variable E^{FK}_{PURxt} should be bold because "alternative ancillary service arrangement" is	The **allocable cost** of **frequency keeping** must be paid by **purchasers** to the **system operator** in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula: … Offtake$_{PURxt}$ is the total **reconciled quantity** in kWh for **purchaser** x across all **grid exit points** in **trading period** t in the **billing period** E^{FK}_{PURxt} is the quantity of any **frequency keeping** provided under any **alternative ancillary service arrangement** for **frequency keeping** authorised by the **system operator** for **purchaser** x in **trading period** t.

#	Clause	Issue	Proposed amendment
		the relevant defined term.	
33.	8.58 – Frequency keeping costs are allocated to purchasers	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $Share_{PURx} = \frac{Fc * \max(0, \Sigma_t (Offtake_{PURxt} - E^{FK}_{PURxt}))}{\Sigma_x \max(0, \Sigma_t (Offtake_{PURxt} - E^{FK}_{PURxt}))}$ Updated: $Share_{PUR_x} = \frac{F_c \times \max\left(0, \sum_t (Offtake_{PUR_{xt}} - E^{FK}_{PUR_{xt}})\right)}{\sum_x \max\left(0, \sum_t (Offtake_{PUR_{xt}} - E^{FK}_{PUR_{xt}})\right)}$
34.	8.59 – Availability costs allocated to generators and HVDC owner	The word “injected” in the variable INJ_{GENxt} should not be in bold as it is not a defined term.	The **availability costs** in a **billing period** must be allocated separately to persons in the North Island and South Island in accordance with the following formula: … INJ_{GENxt} is the **electricity** injected (expressed in **MWh**) by **generating unit** x in **trading period** t into the North Island or South Island as appropriate …
35.	8.59 – Availability costs allocated to generators and HVDC owner	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $Share_t = \frac{Ac_t * m_t}{M_t}$ Updated: $Share_t = \frac{Ac_t \times m_t}{M_t}$
36.	8.65 – Rebates paid for under-frequency events	In the formula, the variable $Rebate_{Xe}$ should be $Rebate_{xe}$.	An **event charge** that has been paid for an **under-frequency event** (referred to as “Event e”) under clause 8.64 or under clause 8.64A must be rebated in accordance with the following formula to persons who are allocated **availability costs** in accordance with clause 8.59: ~~$Rebate_{Xe}$~~ $\underline{Rebate_{xe}}$= $EC_e * Z_{xe}/Z_{tote}$
37.	8.67(2) – Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges	There should not be a space between the j and z in "Qxjz". “Demand” should be in bold as it is a defined term. The words "kvar reference" should not be in bold as this is not a defined term.	(2) Each **connected asset owner** must pay a nominated peak kvar charge calculated in accordance with the following formula:… ~~$Q_{xj\ z}$~~ $\underline{Q_{xjz}}$ is Nom $Peak_{LINESxjz}$, which is the peak **demand** in kvar (in **zone** z) nominated to the **system operator** in advance of, and having effect from, 1 March each year by **connected asset owner** x at its **connected asset owner** kvar reference **node** j $\sum_j$ is the sum across all **connected asset owner** kvar reference **nodes** j of **connected asset owner** x in **zone** z

#	Clause	Issue	Proposed amendment
		The word "node" is a defined term and should be in bold.	
38.	8.67(3) – Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges	The words "kvar reference" should not be in bold as this is not a defined term.	(3) Each **connected asset owner** must pay a monthly peak penalty charge calculated in accordance with the following formula: … $\text{PeakPenaltyCharge}_{\text{LINExz}}$ is the total peak penalty charges for **connected asset owner** x across all **connected asset owner** kvar reference **nodes** j for **connected asset owner** x in **zone** z … $\sum_{j}$ is the sum across all **connected asset owner** kvar reference **nodes** j of **connected asset owner** x in **zone** z $\text{PenaltyQuantity}_{\text{LINExjz}}$ is the "kvar above nominated kvar" quantity for **connected asset owner** x at its **connected asset owner** kvar reference **node** j in **zone** z
39.	8.67(5) – Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges	"Demand" should be in bold as it is a defined term. The words "kvar reference" should not be in bold as this is not a defined term.	(5) Each **connected asset owner** must pay a residual charge or receive a residual payment calculated in accordance with the following formulae: … $\text{BillingPeriodOfftake}_{\text{LINExz}}$ is the sum of **metering information** for **connected asset owner** x across all **connected asset owner** kvar reference **nodes** in **zone** z for the **billing period** for all **trading periods** $\text{BillingPeriodOfftake}_{\text{ALLz}}$ is the sum of **metering information** for all **connected asset owners** across all **connected asset owner** kvar reference **nodes** in **zone** z for the **billing period** for all **trading periods** $\sum_{xj}$ is the sum across all **connected asset owner** kvar reference **nodes** j for all **connected asset owners** x in **zone** z $\sum_{j}$ is the sum across all **connected asset owner** kvar reference **nodes** j of **connected asset owner** x in **zone** z Q_{xjz} is Nom PeakLINESxjz, which is the peak **demand** in kvar (in **zone** z) nominated to the **system operator** in advance of, and having effect from, 1 March each year by **connected asset owner** x at its **connected asset owner** kvar reference **node** j
40.	Schedule 8.1, clause 6 – Special	The words "publish" and "publication"	(1) Before granting a **dispensation**, the **system operator** must issue a draft decision on the application. The draft decision must be **published**

#	Clause	Issue	Proposed amendment
	provisions relating to the grant of dispensations	should be in bold as these are defined terms.	on the **system operator register** and must include— … … (3) A **participant** may make a submission to the **system operator** on the application that resulted in the **publication** of the draft decision no later than 10 **business days** after the draft decision is recorded on the **system operator register**. …
41.	Schedule 8.3	The empowering clause needs to be added.	Schedule 8.3 ~~cl 1.1~~ cls 8.25 and 8.28 Technical codes
42.	Schedule 8.3, Technical Code A, clause 7(1) – Modifications and changes to assets	The term "excluded generator" should not be in bold as it is not defined in clause 1.1.	(1) **Assets** that have been modified, or are proposed to be modified, are deemed to be new **assets** for the purposes of this Code and this **Technical Code** and are subject to the requirements for connection to the **grid** and the requirements for **commissioning assets**. … (c) a new connection of an **embedded generator** to a **local network** other than an excluded **generator** as defined in clause 8.21(1): …
43.	Schedule 8.3, Technical Code A, Appendix B, clause 1(4) – Periodic tests to be carried out	The word "commissioned" should be in bold as it is a defined term.	(4) Each **asset owner** with one or more **generating units commissioned** before 1 January 2016 for which wind is the primary power source must complete the first of each test required in this Appendix for those **generating units** no later than 31 December 2028.
44.	Schedule 8.3, Technical Code B, clause 5A(4) – Request to inform the system operator of available controllable load	The word "network" should be in bold as it is a defined term.	(4) If the **system operator** requests information regarding available **controllable load** under subclause (1), a **connected asset owner** who submits **difference bids** must, as soon as reasonably practicable following a request by the **system operator**— (a) submit to the **system operator** for each **trading period** notified by the **system operator** a **difference bid** that represents a reasonable estimate of the available **controllable load** which the **connected asset owner** can use to decrease its **demand**— (i) at each **conforming GXP** in the **connected asset owner's network** or at a **conforming GXP** nominated by the **system operator** and agreed with the **connected asset owner**; and …
45.	Schedule 8.3, Technical Code C, Appendix A, Table A2	The extra colon at the end of the heading should be deleted.	**Table A2: Requirements of grid owners~~:~~** Each **grid owner** must provide the indications and measurements shown in Table A2 in respect of **assets** connected to, or forming part of, the **grid**. …
		PART 10 – METERING	
46.	10.8(1) – Requirement	The word "notified" should	(1) In this Part, a **participant** who must record, give, produce, or receive information, must do so

#	Clause	Issue	Proposed amendment
	s for information to be recorded, given, produced, or received	not be in bold as it is not a defined term.	in accordance with 1 or more of the following requirements **published** or notified by the **Authority**: …
47.	10.21(1) – When metering equipment provider’s obligations come into effect	The word “equipment” should not be in bold as it is not part of a defined term.	(1) The obligations under this Part of a person who assumes responsibility, or is appointed to be responsible, as the **metering equipment provider**, under clauses 10.19(2) or 10.22, for a **metering installation**, commence,— (a) for an **ICP** that is not also an **NSP**, on the date that is recorded in the **registry** as being the date on which the **metering installation** equipment was installed; or …
48.	10.22(1C) – Change of metering equipment provider	The reference to “subclause 1(A)” should be to “subclause (1A)”.	(1C) If the **losing metering equipment provider** does not carry out the calculation and notify the **gaining metering equipment provider** under subclause ~~1(A)~~ (1A) within the time frame in that subclause, the **gaining metering equipment provider** does not need to comply with subclause (2).
49.	10.22(5) – Change of metering equipment provider	The word “provider” should be in bold as it is part of a defined term.	(5) Despite subclause (2), a **gaining metering equipment provider** is not required to pay the costs if— …
50.	10.33A(1) – When trader may electrically connect point of connection	The word “switch” should be in bold as it is a defined term.	(1) A **trader** may **electrically connect** a **point of connection**, or another **participant** authorised by a **trader** may **electrically connect** a **point of connection**, only if—… (a) for a **point of connection** that is an **ICP**, but which is not an **NSP**,— (i) either— (A) the **trader** is recorded in the **registry** as being responsible for the **ICP**; or (B) if the **ICP** has been **electrically disconnected**, the **trader**— (1) has an arrangement with a **customer** or **embedded generator** at the **ICP**; and (2) initiates a **switch** under clause 2, 9, or 14 of Schedule 11.3 within 2 **business days** of the date of **electrical connection**; and …
51.	10.33A(3) – When trader may electrically connect point of connection	The word “switch” should be in bold as it is a defined term.	(3) A **trader** must not **electrically connect** or authorise the **electrical connection** of a **point of connection** in any of the following circumstances— … (c) a **switch** described in subclause (1)(a)(i)(B)(2) has been withdrawn or reversed. …
52.	10.33A(5) – When trader may electrically	The word “authorised” should not be in	(5) Under subclause (1)(a)(i), if a **trader** or a person authorised by a **trader electrically connects** an **electrically disconnected point of**

#	Clause	Issue	Proposed amendment
	connect point of connection	bold as it is not a defined term. The word "switch" should be in bold as it is a defined term.	**connection** in error, or prior to the **switch** being withdrawn or reversed, the **trader** must— … (b) reimburse the losing **trader** for any direct costs the losing **trader** incurred because of the **electrical connection** of the **point of connection**— (i) in error; or (ii) prior to the **switch** being withdrawn or reversed.
53.	10.33C(5) – When trader may bridge meter at ICP	The word "certified" should be in bold as it is a defined term.	(5) If a **meter** is bridged under subclause (1), in all cases, the **trader** responsible for the **ICP** must— … (c) within 1 **business day** of being advised that the **meter** is bridged, notify the **metering equipment provider** responsible for the bridged **meter** that it is required to reinstate the **meter** so that all **electricity** flowing into the **ICP** flows through a **certified** **metering installation**.
54.	10.33C(6) – When trader may bridge meter at ICP	The words "certified" and "electricity" should be in bold as they are defined terms.	(6) The **metering equipment provider** receiving the notice under subclause (5)(c) must reinstate the **meter** so that all **electricity** flowing into the **ICP** flows through a **certified** **metering installation** within 5 **business days** of receiving the notice.
55.	10.37(1) – Active and reactive measuring and recording requirements	The words "category 3" are in bold but it is not a defined term.	(1) A **metering equipment provider** must ensure that each **half-hour metering installation** that is a category 3 **metering installation,** or higher category of **metering installation**, **certified** after 29 August 2013, measures and separately records, in accordance with this Part …
56.	10.48(3) – Correction of defects and inaccuracies in raw meter data	There is a word missing.	(3) A **metering equipment provider** must, within 10 **business days** of being advised under subclause (1), advise the **reconciliation participant** responsible for providing **submission information** for the **point of connection**, of the correction factors referred to in clause 10.46(1)(h) and the period referred to in clause 10.46(1)(i).
57.	Schedule 10.7, clause 6(1) – Determining metering installation incorporating current transformer to be lower category	The word "the" is in bold but is not part of a defined term.	(1) When determining the category of a **metering installation** under clause 5(a), an **ATH** may under subclause (2) determine the category of a **metering installation** to be lower than would otherwise be the case under clause 5(a) only in 1 of the following circumstances: … (c) if the **metering installation** uses less than 0.5 GWh in any 12 month period: …
58.	Schedule 10.7, clause 8A(2) – ATH amends certification reports	The words "category" and "expiry date" are in bold but they are not defined terms.	(2) An amendment under subclause (1) must not— (a) change the category of the **metering installation**: (b) extend the expiry date in the **certification report**: …

#	Clause	Issue	Proposed amendment
59.	Schedule 10.7, clause 20(1) – **Cancellation of certification of metering installations**	The words "service access interface" should be "services access interface" as this is the defined term.	(1) The **certification** of a **metering installation** is automatically cancelled on the date on which any 1 of the following events takes place: … (j) the **metering installation** is a **half-hour metering installation** and was **certified** after 29 August 2013, the **services access interface** is the **metering equipment provider's back office**, and the **metering equipment provider**— …
60.	Schedule 10.7, clause 37(2) – Data storage device certification expiry date	The words "expiry date" are in bold but it is not a defined term.	(2) The **data storage device certification** expiry date must— (a) for a **data storage device** that is integral to a **meter**, be no later than the **meter certification** expiry date; or …
61.	Schedule 10.7, clause 41(2) – Certification stickers	The words "certification date" are in bold but it is not a defined term.	(2) An **ATH** attaching a **metering installation certification sticker** must ensure that it shows— (b) the most recent **certification** date of the metering installation; and …
62.	Schedule 10.7, clause 41(7)	The word "certification" should be in bold as it is a defined term.	The combined sticker under subclause (5) is immediately invalid if— (a) the **metering installation certification** expiry date changes; or
63.	Schedule 10.7, clause 45(1A)	The word "certification" should be in bold as it is a defined term.	When inspecting a sample of **category 1 metering installations** under subclause (1)(b), the **metering equipment provider** must— … (b) perform the first inspection in the same calendar year the oldest **metering installation** reaches 84 months since **certification**.
64.	Schedule 10.7, clause 48(1A)	The word "control device" should be in bold as it is a defined term.	(1A) A **distributor** may interfere with a **metering installation** without authorisation of the **metering equipment provider** responsible for the **metering installation** to reset a load control switch contained within a load **control device** or bridge or unbridge a load control switch if— … (b) the **distributor** provides the load control signal to the load **control device**.
65.	Schedule 10.7, clause 48(1E) – Removal or breakage of seals	The word "generation" should not be in bold as it is not a defined term in the Code.	(1E) A **trader** may remove or break a seal in a **metering installation** without authorisation of the **metering equipment provider** responsible for the **metering installation**— (a) to **electrically connect** the load or generation measured by the **meter** if the load or generation has been **electrically disconnected** at the **meter**; or (b) to **electrically disconnect** the load or generation measured by the **meter** if the **trader** has exhausted all other appropriate methods of **electrical disconnection**; or (c) to bridge the **meter**.

#	Clause	Issue	Proposed amendment
66.	Schedule 10.8, clause 9(1) – Onsite calibration and certification	The words "reference conditions" are in bold but it is not a defined term.	(1) A **certifying ATH** may only **calibrate** a **metering component** onsite— … (b) by— … (ii) ensuring that— (A) the effects of any departures from the reference conditions specified in the relevant standards listed in Table 5 of Schedule 10.1 can accurately and reliably be calculated; and …
PART 11 – REGISTRY INFORMATION MANAGEMENT			
67.	11.1 – Contents of this Part	The Electricity Industry Participation Code Amendment (Improving Consumer Access to their Electricity Information) 2025 made amendments to clauses 11.32A and 11.32B but omitted to also update the contents clause.	This Part— … (f) requires **retailers** to give **consumers** their **electricity** information ~~about their own consumption of **electricity**~~; and …
68.	11.26 – Reports to reconciliation manager	The words "non half-hour metering" should be in bold as it is a defined term.	By 1600 hours on the 4th **business day** of each calendar month… the **registry manager** must deliver the following reports to the **reconciliation manager**: (a) a report identifying the number of **ICP days** per **NSP**, differentiated by **half-hour metering** type or **non half-hour metering** type (for the purpose of this clause, **half-hour metering** type on the **registry** must be reported as **half hour**, and all other metering types must be reported as non **half hour**) attributable to each **trader** for those **NSPs** that are recorded on the **registry** as consuming **electricity** at any time during, as the case may be, that **consumption period** or any of those **consumption periods**: …
69.	Schedule 11.1, clause 1(3) – ICP identifiers	The word "identify" is in bold but is not a defined term.	(3) Despite any clause to the contrary, only the obligations in this clause and clauses 2, 6 and 7(1)(a) to (e), (l) and (m) apply if an **ICP identifier** is used to identify a— (a) **point of connection** between an **embedded network** and its parent **network**; or (b) **point of connection** between **shared unmetered load** and its **network**.
70.	Schedule 11.1, clause 5 – Electrical load	The words "network supply point" should be replaced by NSP	The electrical load associated with an **ICP** is deemed to be supplied through 1 ~~**network supply point**~~ **NSP** only.

#	Clause	Issue	Proposed amendment
		as this is the defined term.	
71.	Schedule 11.1, clause 11(1) – Correction of errors in the registry	The word ”trading” is in bold but is not a defined term.	(1) By 0900 hours on the 1st **business day** of each **reconciliation period**, the **registry manager** must provide to each **participant** who is required to submit **submission information**, the following: (a) a list of the **ICPs** at which the **participant** is recorded on the **registry** as trading during each **consumption period** being revised in the **reconciliation period**: …
72.	Schedule 11.1, clause 19(2) – “Inactive” status	The word “ICP” should be in bold as it is a defined term.	(2) The **ICP** status of “Inactive” may be managed by the relevant **distributor** only to indicate that— … (b) the **ICP** cannot be **electrically disconnected** following a request for **electrical disconnection**.
73.	Schedule 11.1, clause 25(5) – Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network	The word “NSP” should be in bold as it is a defined term.	(5) The **participant** required to give notice under subclause (1) must give notice no later than 30 days prior to the intended date of creation or **decommissioning** of the **NSP**.
74.	Schedule 11.3, clause 4(1) - Event dates	The word “losing” is in bold but it is not a defined term. The word “trader” should be in bold as it is a defined term.	(1) The losing **trader** must establish **event dates** so that— (a) no **event date** is more than 10 **business days** after the date on which the **registry manager**, under clause 22(a), makes written notice available to the losing **trader**; and …
75.	Schedule 11.3, clause 13 – Gaining trader switch processes	The word “ICP” should be in bold as it is a defined term.	(1) A gaining **trader** switch process applies only when a **trader** (the “gaining **trader**”) has an arrangement with a customer or **embedded generator** to**—** (a) trade **electricity** with the customer or **embedded generator** at an **ICP** at which another **trader** (the “losing **trader**”) trades **electricity** with the customer or **embedded generator**, and one of subparagraphs (i) to (iii) applies— … (ii) at the **ICP**— …
PART 11A – CONSUMER CARE			
76.	Schedule 11A.1, clause 36(3) – Disconnection of uncontracted premises	The word “uncontacted” should be “uncontracted”.	(3) The notices required under subclauses (1)(b) and (1)(c): (a) may be provided in the same notice or in separate notices at different times; (b) must be in writing and delivered to the ~~**uncontacted**~~ **uncontracted** **premises**; and

#	Clause	Issue	Proposed amendment
			(c) must include information about how to contact the **retailer** to discuss signing up as a new **customer**.
		PART 12 – TRANSPORT	
77.	12.10(3) – Default transmission agreements	The word "assets" should be in bold as it is a defined term.	(3) The service levels set out in Schedule 5 of a **default transmission agreement** must be determined on the following basis: … (b) the service levels for the voltage range specified in the capacity service measures for each **branch** must be consistent with,— … (ii) for **assets** of voltages less than 50kV, the normal operating voltage of the component **assets**: …
78.	12.50 – Copies of other agreements to be provided to Authority	The word "grid" should be in bold as a defined term.	If requested to do so by the **Authority**, **Transpower** or a **participant** must provide a copy of any written agreement for connection to and/or use of the **grid** that **Transpower** or the **participant** is a party to and that was entered into before 28 June 2007, including any amendments.
79.	12.57 – Principles of grid reliability standards	The word "assets" should be in bold as it is a defined term.	The **grid reliability standards** should— (a) take into account that transmission investments are long-lived **assets** and require a long-term planning perspective; and (b) reflect the public interest in reasonable stability in planning, having regard to the long term nature of investment in transmission **assets**; and …
80.	12.77 – Recovery of investment costs by Transpower	The word "the" is in bold but is not part of a defined term.	The costs incurred by **Transpower** (irrespective of when they are incurred) in relation to an **approved investment** are recoverable by **Transpower** from **designated transmission customers** on the basis of the **transmission pricing methodology** and must be paid by **designated transmission customers** accordingly.
81.	12.110(1) – Incorporation of interconnection asset capacity and grid configuration by reference	The words "interconnection asset" and "grid" should be in bold as they are defined terms.	(1) The **interconnection asset** capacity and **grid** configuration is incorporated by reference in this Code. …
82.	12.114(1) – Investments to met the grid reliability standards	The word "meet" is in bold but is not a defined term. The word "asset" should be replaced by interconnection asset and appear	(1) If a **grid reliability report** identifies, in accordance with clause 12.76(1)(c), that the power system is not reasonably expected to meet the **N-1 criterion** at a **grid exit point** at all times over the 5 years following the date on which the report is **published** and that this is due to an **interconnection asset**, **Transpower** must— … (b) if the **interconnection asset** does not meet the **grid reliability standards**, consider reasonably

#	Clause	Issue	Proposed amendment
		in bold as it is a defined term.	practicable options for ensuring that the **grid reliability standards** can be met in respect of that **interconnection asset**; and …
83.	12.117 – Permanent removal of interconnection assets from service or permanent grid reconfiguration	The word "MWh" should be in bold as it is a defined term.	… (2) When **Transpower** is required to apply a net benefit test, **Transpower** must— (a) estimate the following costs: … (iii) any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**, arising as a result of the removal of the **interconnection asset** or the reconfiguration of the **grid**: … (b) estimate the following benefits: … (iii) any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**, arising as a result of the removal of the **interconnection asset** or the reconfiguration of the **grid**: … (9) The estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy** under subclause (2) must be based on the value of **expected unserved energy** in clause 4 of Schedule 12.2 and **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer. …
84.	12.127(1) – Transpower to report on availability and reliability	The word "and" is missing from the end of subclause (i).	(1) By 30 November in each year, **Transpower** must **publish** and provide to the **Authority** information on availability and reliability of **interconnection assets** including— … (i) a comparison of the information required by paragraphs (a) to (f) against the availability and reliability index measures for **interconnection branches**, **shunt assets** and the **HVDC link** included in a schedule to this Part under clause 12.126; and …
85.	12.141(2) – Consideration of likely effects of planned outages	The word "MWh" should be in bold as it is a defined term. The word "planned" should be in bold as it is part of a defined term.	(2) The requirements in subclause (1) that the **Outage Protocol** may provide are— (a) if a proposed **planned outage** is likely to result in the power system failing to meet the **grid reliability standards**, but is not expected to give rise to **binding constraints** or result in loss of **supply** to **consumers**, **Transpower** must— (i) estimate the following costs: …

#	Clause	Issue	Proposed amendment
			(C) if the **outage** will result in an increased risk of loss of **supply**, any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (ii) estimate the following benefits: (A) if the **outage** will result in a decreased risk of loss of **supply**, any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (b) if a proposed **planned outage** is likely to give rise to **binding constraints**, whether or not the **outage** is also likely to result in a loss of **supply** to **consumers**, **Transpower** must— (i) estimate the following costs: … (C) if the **outage** will result in an increased risk of loss of **supply**, any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (ii) estimate the following benefits: (BA) if the **outage** will result in a decreased risk of loss of **supply**, any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: … (c) if a proposed **planned outage** is likely to lead to loss of **supply** to **consumers**, whether or not the **outage** is also likely to give rise to **binding constraints**, **Transpower** must— (i) estimate the following costs: … (C) any increase in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**, arising from the loss of **supply** during the **outage**: … (ii) estimate the following benefits: … (B) if the **outage** will result in a decreased risk of loss of **supply**, any decrease in the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy**: …
86.	12.141(3) – Consideration of likely effects of	The word "MWh" should be in bold as it is a defined term.	(3) In providing for the matters referred to in subclause (2), the **Outage Protocol** must include the following requirements: …

#	Clause	Issue	Proposed amendment
	planned outages		(d) the estimate of **expected unserved energy** in **MWh** multiplied by the value per **MWh** of that **expected unserved energy** under subclause (2) must— …
87.	Schedule 12.3, clause 2(2)	The word “assets” should be in bold as it is a defined term.	(2) The **core grid** consists of those **assets** that comprise the transmission links listed in Table 1 below: …
88.	Schedule 12.4, clause 3 – definition of **capacity**	The word “distribute” should not be in bold as it is not a defined term.	**capacity** means the rated capacity of an asset to (as the case may be)— (a) consume or generate **electricity**; or (b) take **electricity** from or inject **electricity** into a **network**; or (c) transmit or distribute **electricity**, in each case measured in units appropriate for the context
89.	Schedule 12.4, clause 3 – definition of **injection**	The words “grid point of injection” should be “grid injection point” as this is the defined term.	**injection** means— (a) for a **trading period** and a **customer’s grid point of connection**, the positive net quantity of **electricity** flow into the **grid** at the ~~**grid point of injection**~~ **grid injection point** from the **customer’s** assets during the **trading period** (if any); and …
90.	Schedule 12.4, clause 3 – definition of	Add a new subclause to clarify that words in bold in this Schedule are defined in either this clause or in clause 1.1 of the Code.	(2) In this **transmission pricing methodology**, words and phrases appear in bold to alert the reader to the fact that they are defined in this clause or clause 1.1.
91.	Schedule 12.4, clause 20(4) – Connection and Interconnection Nodes and Links	The words “connection” and “interconnection” are in bold but are not defined terms.	(4) If a group of **nodes** or **links** that are to be provided as part of the same project are **commissioned** in a staged manner, the connection or interconnection status of each **node** and **link** in the group must be determined prospectively based on all **nodes** and **links** in the group being **commissioned**. However— …
92.	Schedule 12.4, clause 24(4) – Calculation of Connection Charges	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $TACC = TAC \times \frac{\sum_l ACC_l}{\sum_l ACC_{l\,total}}$ Updated: $TACC = TAC \times \frac{\sum\limits_{l} ACC_l}{\sum\limits_{l} ACC_{l\ total}}$

#	Clause	Issue	Proposed amendment
93.	Schedule 12.4, clause 51(6) – Calculation of Market Regional NPB based on Quantity	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$ Updated: $MRNPB = \frac{1}{\sum\limits_s W_s} \sum\limits_s (EMBD_s \times W_s)$
94.	Schedule 12.4, clause 52(8) – Calculation of Market Regional NPB based on Price and Quantity	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$ Updated: $MRNPB = \frac{1}{\sum\limits_s W_s} \sum\limits_s (EMBD_s \times W_s)$
95.	Schedule 12.4, clause 53(6) – Ancillary Service Regional NPB	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $ASRNPB = \frac{1}{\sum_s W_s} \sum_s (EASBD_s \times W_s)$ Updated: $ASRNPB = \frac{1}{\sum\limits_s W_s} \sum\limits_s (EASBD_s \times W_s)$
96.	Schedule 12.4, clause 54(7) – Reliability Regional NPB	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $RRNPB = \frac{1}{\sum_s W_s} \sum_s (ERBD_s \times W_s)$ Updated: $RRNPB = \frac{1}{\sum\limits_s W_s} \sum\limits_s (ERBD_s \times W_s)$
97.	Schedule 12.4, clause 64(2) – Regional NPB	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas	Current: $RNPB = \frac{1}{\sum_t W_t} \sum_t (SMC_t \times W_t) \times F$ Updated: $RNPB = \frac{1}{\sum\limits_t W_t} \sum\limits_t (SMC_t \times W_t) \times F$

<table>
<tr><th>#</th><th>Clause</th><th>Issue</th><th>Proposed amendment</th></tr>
<tr><td></td><td></td><td>are displayed to the right rather than displaying as redlined.</td><td></td></tr>
<tr><td>98.</td><td>Schedule 12.4, clause 64(5) – Regional NPB</td><td>The formulas in the table have been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.</td><td>Current:
<table>
<tr><th>connection region A</th><th>connection region B</th><th>connection region C</th></tr>
<tr><td>$\frac{G_a}{(G_a+L_a+F_{a\_b})}$</td><td>$\frac{F_{a\_b}}{(G_b+L_b+F_{a\_b}+F_{b\_c})}$</td><td>$\frac{F_{b\_c}}{(G_c+L_c+F_{b\_c})}\left(\frac{F_{a\_b}}{G_b+F_{a\_b}}\right)$</td></tr>
<tr><td>0</td><td>$\frac{G_b}{(G_b+L_b+F_{a\_b}+F_{b\_c})}$</td><td>$\frac{F_{b\_c}}{(G_c+L_c+F_{b\_c})}\left(\frac{G_b}{G_b+F_{a\_b}}\right)$</td></tr>
<tr><td>0</td><td>0</td><td>$\frac{G_c}{(G_c+L_c+F_{b\_c})}$</td></tr>
<tr><td>$\frac{L_a}{(G_a+L_a+F_{a\_b})}$</td><td>0</td><td>0</td></tr>
<tr><td>$\frac{F_{a\_b}}{(G_a+L_a+F_{a\_b})}\left(\frac{L_b}{L_b+F_{b\_c}}\right)$</td><td>$\frac{L_b}{(G_b+L_b+F_{a\_b}+F_{b\_c})}$</td><td>0</td></tr>
<tr><td>$\frac{F_{a\_b}}{(G_a+L_a+F_{a\_b})}\left(\frac{F_{b\_c}}{L_b+F_{b\_c}}\right)$</td><td>$\frac{F_{b\_c}}{(G_b+L_b+F_{a\_b}+F_{b\_c})}$</td><td>$\frac{L_c}{(G_c+L_c+F_{b\_c})}$</td></tr>
</table>
Updated:
<table>
<tr><th>connection region A</th><th>connection region B</th><th>connection region C</th></tr>
<tr><td>$\frac{G_a}{(G_a+L_a+F_{a_b})}$</td><td>$\frac{F_{a_b}}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>$\frac{F_{b_c}}{(G_c+L_c+F_{b_c})}\left(\frac{F_{a_b}}{G_b+F_{a_b}}\right)$</td></tr>
<tr><td>0</td><td>$\frac{G_b}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>$\frac{F_{b_c}}{(G_c+L_c+F_{b_c})}\left(\frac{G_b}{G_b+F_{a_b}}\right)$</td></tr>
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<tr><td>$\frac{L_a}{(G_a+L_a+F_{a_b})}$</td><td>0</td><td>0</td></tr>
<tr><td>$\frac{F_{a_b}}{(G_a+L_a+F_{a_b})}\left(\frac{L_b}{L_b+F_{b_c}}\right)$</td><td>$\frac{L_b}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>0</td></tr>
<tr><td>$\frac{F_{a_b}}{(G_a+L_a+F_{a_b})}\left(\frac{F_{b_c}}{L_b+F_{b_c}}\right)$</td><td>$\frac{F_{b_c}}{(G_b+L_b+F_{a_b}+F_{b_c})}$</td><td>$\frac{L_c}{(G_c+L_c+F_{b_c})}$</td></tr>
</table></td></tr>
<tr><td>99.</td><td>Schedule 12.4, clause 83(5) – Benefit-based Charge Adjustment Event: New Customer</td><td>A closing bracket is missing in the heading of the third table.</td><td>(5) The following tables illustrate the application of subclause (3) to a new customer (customer E) entering regional customer group Y for a post-2019 BBI under the price-quantity method where regional customer group Y is not a future regional customer group:
…
After (paragraph (3)(d))</td></tr>
<tr><td>100.</td><td>Schedule 12.4, clause 83(5C) – Benefit-based Charge Adjustment Event: New Customer</td><td>The word “part” is in bold but is not part of a defined term.

The words “simple method benefit cap” should be simple method BBC cap” which is the defined term.</td><td>(5C) If this subclause applies under subclause (5A), Transpower must, instead of applying the new customer’s benefit-based charges for the relevant post-2019 BBIs under the simple method calculated under subclause (3)—
(a) attribute part of the new customer’s simple method BBC cap to each investment region in respect of which the relevant regional customer group has positive regional NPB as follows:
…
where</td></tr>
</table>

#	Clause	Issue	Proposed amendment
			$SMBC_{region}$ is the part of the new **customer's simple method BBC cap** attributed to the **investment region** **…** (b) calculate the new **customer's BBI customer allocation** for each relevant **post-2019 BBI** (CA) as follows: $$CA = \frac{SMBC_{region}}{CC_{region\ total}}$$ where $SMBC_{region}$ is the part of the new **customer's** ~~**simple method benefit cap**~~ **simple method BBC cap** attributed to the **investment region** in which the relevant **post-2019 BBI** is located under paragraph (a) …
101.	Schedule 12.4, clause 88(3) – Benefit-based Charge Adjustment Event: Changed Point of Connection	The word "customer" is not fully in bold and is a defined term.	(3) If the notional new **customer's BBI customer allocation** for a relevant **BBI** is equal to or more than the notional exiting **customer's BBI customer allocation** for the relevant **BBI**, **Transpower** must— (a) apply paragraph 85(2)(b) for the connecting **customer** and relevant **BBI**; and …
102.	Schedule 12.4, clause 112(2) – Cap Recovery Charge	The term "cap-recovery relevant charges" should be cap recovery-relevant charges".	(2) A **customer's annual cap recovery charge** for a **pricing year** (ACRC) is calculated as follows: … $CRRC_{total}$ is the total of all **customers**' **cap recovery-relevant charges** for the **pricing year**, excluding ~~**cap-recovery relevant charges**~~ **cap recovery-relevant charges** for **customers** who receive a **cap reduction** for the **pricing year**.
103.	Schedule 12.4, clause 117(2) – Calculation of Alternative Project Costs	The word "electrical" should not be in bold as it is not a defined term.	(2) For the purposes of calculating the **alternative project costs**— (a) the value of any increase or decrease in electrical losses that would result from the **alternative project** must be included as an operating cost of the **alternative project** (with a decrease being treated as a negative cost); and …
104.	Schedule 12.4, clause 122(3) – Calculation of Back-dated Prudent Discounts	The word "agreement" should not be in bold as it is not part of the defined term.	(3) If a **back-dated prudent discount** is not reflected in the **transmission charges** for the **back-dated prudent discount's start pricing year** or any later **pricing year** during the term of the relevant **prudent discount** agreement (a relevant **pricing year**), **Transpower** must carry out a wash-up of the **prudent discount recipient's transmission charges** for each relevant **pricing year** so that the **prudent discount recipient** is not over-charged **transmission charges** for the relevant **pricing years**. The wash-up— …

#	Clause	Issue	Proposed amendment
105.	Schedule 12.4, clause 123 – Calculation of Annuity	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $AN = \frac{PVAPC}{\sum_{n=1}^{N} \frac{1}{(1+r)^n}}$ Updated: $AN = \frac{PVAPC}{\sum\limits_{n=1}^{N} \frac{1}{(1+r)^n}}$
106.	Schedule 12.4, clause 133 – Purpose of Stand-alone Cost Prudent Discount	The word "agreement" should not be in bold as it is not part of the defined term.	The purpose of a **stand-alone cost prudent discount** is to help ensure this **transmission pricing methodology** does not result in a **customer** paying **transmission charges** that exceed the efficient stand-alone cost of the **transmission services** the **customer** currently receives. A **stand-alone cost prudent discount** achieves this by replacing the **prudent discount recipient's connection charges**, **benefit-based charges** and **residual charge** with an annuity under a **prudent discount** agreement equal to the **alternative project costs** of an **efficient stand-alone investment**.
107.	Schedule 12.6, clause 37.2 - Real time signal of demand by Region from SCADA	The words "regional demand" should not be in bold as it is not a defined term. The words "defined in" are potentially confusing in this context and should be replaced with "calculated under". This does not change the meaning but adds clarity.	Transpower must provide to the Customer information on the regional demand (as calculated under~~defined in~~ the **transmission pricing methodology**) for each region that the Customer has a **connection location**. This information is to be derived from **SCADA**, updated at least every five minutes, and updated not more than five minutes after the regional demand is measured.
		PART 13 – TRADING ARRANGEMENTS	
108.	13.2E(1) – Publication of information in quarterly disclosure reports by the Authority	The words "publish" and "publication" should be in bold as they are defined terms.	(1) The **Authority** may **publish** any information submitted to it in a **quarterly disclosure report**, the certification required by clause 13.2D(1)(a) and the report required by clause 13.2D(1)(b), provided any such **publication** does not involve the **publication** of— …
109.	13.2G – Authority may require review of disclosure requirements	The clause does not need to be numbered subclause (1) as it is the only part of the clause.	~~(1)~~ The **Authority** may, in its discretion, require a review by an independent person of whether a **major participant** may not have complied with any or all of clauses 13.2B to 13.2D.

#	Clause	Issue	Proposed amendment
	or certification by independent person		
110.	13.3A(5) – Approval process for dispatch-capable load stations	The words "dispatch capable load station" are missing a hyphen.	(5) Where the **system operator** suspends such an approval under subclause (4), the **system operator** must continue such suspension until— (a) the **purchaser** re-commences operating as a **dispatch notification purchaser** in respect of the relevant **dispatch-capable load station**; or
111.	13.3E(3) – Approval process for dispatch notification purchasers	The word "relevant" should not be in bold as it is not part of a defined term.	(3) If the **system operator** approves a **purchaser's** application to become a **dispatch notification purchaser**,— … (c) the **purchaser** in respect of which approval is granted is not a **dispatch notification purchaser** while approval for the relevant **dispatch-capable load station** is suspended under clause 10 of Schedule 13.8.
112.	13.4 – Contents of this subpart	The word "trading" is in bold but is not a defined term.	This subpart provides for processes to facilitate trading by which**—** …
113.	13.6 – Requirements for generators when submitting offers	The semi-colon at the end of the chapeau should be a colon.	(1) Each **generator** with a **point of connection** to the **grid**, and each **embedded generator** required by the **system operator** to submit an **offer** under clause 8.25(5), must— (a) for a **generator** other than an **intermittent generator**~~;~~: … (b) subject to subclause (2), for an **intermittent generator**~~;~~: …
114.	13.9B(3) – Offer requirements for intermittent generators	The reference to "clause 13.6(1)(b)(ii)" should be a reference to "clause 13.6(1)(b)(iii)".	(3) If clause 13.6(1)(b)~~(ii)~~(iii) applies, each **forecast of generation potential** must use either: (a) the long-term seasonal average for that time of year for that **intermittent generating station** and **trading period**: or …
115.	13.9C – Information must be provided in response to an approved forecaster request	The word "response" should not be in bold as it is not a defined term. The words "approved forecaster" should be "approved forecast provider" as this is the defined term.	An **intermittent generator** required to use an **approved forecast** under subclause (2) must, in response to a request from the ~~**approved forecaster**~~ **approved forecast provider**, provide any information reasonably required by the ~~**approved forecaster**~~ **approved forecast provider** for the purpose of providing an **approved forecast**, as soon as practicable after receiving the request.
116.	13.19C(4) – Dispatch notification	The word "offer" should be in bold	(4) A **dispatch notification generator** that submits a revised **offer** under this clause—

#	Clause	Issue	Proposed amendment
	purchasers and dispatch notification generators to submit revised bids and offers in certain circumstances	as it is a defined term.	(a) is deemed to have submitted an **offer** in which the **MW** specified in the **offer** is 0 for the **trading period** following the **trading period** to which the revised **offer** relates; and …
117.	13.82(2)	Capacity reserve is no longer necessary in this clause	(2) Each **participant** to which this clause applies must comply with a **dispatch instruction** properly issued by the **system operator** under clause 13.72(1)(a) unless,—… (b) the **generating plant** or **dispatch-capable load station** is already responding to an automated signal to activate— (i) ~~**capacity reserve**; or~~ *[Revoked]* (ii) **instantaneous reserve**; or (iii) **automatic under-frequency load shedding**; or (iv) **over frequency reserve**; or …
118.	13.98 – Generators and ancillary service agents may change other parameters	The word "a" is in bold but is not part of the defined term.	Despite clause 13.97(2), during a **grid emergency**,— … (c) despite clauses 13.6 to 13.27, a **generator** may— (i) submit revised **offers** in respect of **generating plant** already subject to an **offer** before the **grid emergency**, so that the total **MW** offered by the **generator** from the **generating plant** for that **trading period** is increased; and …
119.	13.136(1A) – Offered embedded generators to provide half-hour metering information	The word "generation" is in bold but it is not a defined term in the Code.	(1A) For the purposes of subclause (1), the relevant **grid owner** is— (a) in relation to a **generator** (other than an **embedded generator**), the **grid owner** of the **grid** to which the **generator's** generation is connected; and …
120.	13.173C – Authority to determine whether pricing error has occurred	The words "pricing error" should be in bold as it is a defined term.	(2) The **Authority** must, as soon as practicable after making its determination,— … (b) give a written notice on **WITS** that includes the following information: (i) the name of the error claimant (where a **pricing error** has been claimed): …
121.	13.219(1) – Information that must be submitted	The word "party" should be in bold as it is a defined term.	(1) The **party** specified in clause 13.218 must submit the following information to the **approved system** in relation to every **risk management contract**, excluding exchange-traded **risk management contracts** where the **parties** have provided consent under clause 13.236AA: …

#	Clause	Issue	Proposed amendment
122.	13.205 – Calculation of constrained on amounts attributable to system operator	The words "constrained on payment" are in bold but it is not a defined term.	If a **constrained on situation** occurs during a **trading period** in a previous **billing period**, and the **clearing manager** receives notice of the **constrained on situation** under clause 13.76, the **clearing manager** must determine the portion of the **constrained on amounts** calculated under clause 13.204 attributable to the **system operator** for each **generator** or each **ancillary service agent** as follows: … (b) if the **system operator** has advised the **clearing manager** that a non-security **constrained on situation** occurred the **system operator** must be allocated a **constrained on amount** calculated in accordance with the following formula: … TCONP is the total constrained on payment for that **trading period** …
123.	13.231A – Audit process	The words "auditor" and "participant" are not in bold but are defined terms.	… (4) Before the **audit** report is submitted to the **Authority**, the **auditor** must refer any apparent failure by the **participant** to comply with this subpart that the **auditor** has identified to the **participant** for comment within the timeframe specified by the **auditor**. (5) The **audit** report must include any comments from the **participant** on any apparent non-compliance that the **auditor** referred to the **participant** under subclause (4) if the **participant** provided comments to the **auditor** within the time specified by the **auditor**. …
124.	13.233(1) – WITS manager and Authority must keep certain information confidential	The words "service providers" are in bold but it is not a defined term.	(1) The **Authority** must keep, and ensure that the **WITS manager** keeps, information submitted to the **approved system** under this subpart confidential, unless— (a) the information is provided by the **Authority** to subcontractors or service providers that the **Authority** appoints to provide services for the purposes of this subpart, and those subcontractors or service providers have agreed to keep that information confidential, on the same terms as apply to the **Authority** under this clause; or …
125.	13.236A – Disclosing participants must prepare and submit spot price risk disclosure statements	The word "wash-up" should be "washup" as this is the defined term.	(4) A **participant** is not required to comply with this clause for a quarter if it is a **disclosing participant** in relation to the quarter only because it is subject to a ~~**wash-up**~~ **washup** in that quarter.

#	Clause	Issue	Proposed amendment
126.	13.256(3) – Generator retailers must provide ITP information to the Authority	The words "retailer generator" should be "generator retailer" as this is the defined term.	(3) The information provided by a **generator retailer** under subclause (2)(b) must include the following: (a) a breakdown of the key components or factors which make up the **retail ITP** expressed as an amount in dollars and cents per **MWh** that each key component or factor comprises of the average load weighted **retail ITP** required by subclause (2)(a), and which must include (if relevant) the following components or factors: … (ii) the distribution of the total electrical load across locations, including the adjustment, calculated on an average load weighted basis in **MWh**, that the ~~**retailer** generator~~ **generator retailer** used to determine the **retail ITP** for the **electricity** sold to **mass market customers** beyond a **node** specified in an **ASX NZ electricity future**: …
127.	13.258 – Publication of ITP information by the Authority	The word "publish" should be in bold as it is a defined term.	The **Authority** may **publish** any **ITP information** or information submitted to it under clause 13.257, as the **Authority** sees fit.
128.	13.279 – Appointment of auditor	The words "audit" and "auditor" are not in bold but are defined terms.	(1) The **Authority** may, in its discretion, carry out an **audit** as to whether a **generator** has complied with this subpart. (2) If the **Authority** decides under subclause (1) that a **generator** should be subject to an audit— (a) the **Authority** must require the **generator** to nominate an appropriate **auditor**; and (b) the **generator** must provide that nomination to the **Authority** within a reasonable timeframe. (3) The **Authority** may appoint the **auditor** nominated by the **generator** or a different **auditor**, having regard to any factors it considers relevant in the circumstances, including— (a) the expected quality of the **audit**: (b) the expected costs of the **audit**. (4) If the **generator** fails to nominate an appropriate **auditor** within 20 **business days**, the **Authority** may appoint an **auditor** of its own choice.
129.	13.280 – Carrying out of audit	The words "audit" and "auditor" are not in bold but are defined terms.	(1) A **generator** subject to an **audit** under clause 13.279 must, on request from the **auditor**, provide the **auditor** with such information as the **auditor** reasonably requires in order to carry out the **audit**. (2) The **generator** must provide the information no later than 20 **business days** after receiving a request from the **auditor** for the information. (3) The **generator** must ensure that the auditor provides the **Authority** with an **audit** report on the **generator's** compliance with this subpart within the timeframe specified by the **Authority**.

#	Clause	Issue	Proposed amendment
			(4) The **audit** report must include any other information the **Authority** may reasonably require. (5) Before the **audit** report is provided to the **Authority**, any identified failure of the **generator** to comply with this subpart must be referred back to the **generator** for comment. (6) The comments of the **generator** must be included in the **audit** report. (7) The **audit** report must not contain any contract that the **generator** has provided to the **auditor** unless the contract meets the definition of a **materially large contract**.
130.	13.281 – Payment of costs relating to audits	The words “audit” and “auditor” are not in bold but are defined terms.	(1) If an **audit** establishes, to the reasonable satisfaction of the **Authority**, that a **generator** may not have complied with this subpart (whether or not the **Authority** appoints an investigator to investigate the alleged breach), the **generator** must pay for the **audit**. (2) If the **Authority** considers that the non-compliance of the **generator** is minor or there is any other reason in the **Authority’s** view that means the **generator** should not pay the costs of the **audit**, the **Authority** may, in its discretion, determine the proportion of the costs of the **audit** that are to be paid by the **generator**, and those costs must be paid by the **generator** with any remaining proportion of costs paid by the **Authority**. (3) If an **audit** establishes to the reasonable satisfaction of the **Authority** that the **generator** has complied with this subpart, the **generator** is not required to pay any of the **auditor’s** costs and the **Authority** will pay the **auditor’s** costs.
131.	Schedule 13.3, clause 8(1) – The objective function	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $\text{Maximise} \left\{ \begin{array}{c} \overbrace{\sum_{i,j} D_{i,j} \ x \ BP_{i,j}}^{\text{Gross Consumer Benefit}} \\ \text{minus} \\ \overbrace{\sum_{i,j} G_{i,j} \ x \ OP_{i,j}}^{\text{Cost of Generation}} \\ \text{minus} \\ \overbrace{\sum_{i,j} R_{i,j}^{GR,f} \ x \ OP_{i,j}^{GR,f} + \sum_{i,j} R_{i,j}^{IL,f} \ x \ OP_{i,j}^{IL,f}}^{\text{Cost of Fast Instantaneous Reserves}} \\ \text{minus} \\ \overbrace{\sum_{i,j} R_{i,j}^{GR,s} \ x \ OP_{i,j}^{GR,s} + \sum_{i,j} R_{i,j}^{IL,s} \ x \ OP_{i,j}^{IL,s}}^{\text{Cost of Sustained Instantaneous Reserves}} \end{array} \right\}$

#	Clause	Issue	Proposed amendment
			Updated: $\text{Maximize} \left\{ \begin{array}{c} \overbrace{\sum_{i,j} D_{i,j} \times BP_{i,j}}^{\text{Gross Consumer Benefit}} \\ \text{minus} \\ \overbrace{\sum_{i,j} G_{i,j} \times OP_{i,j}}^{\text{Cost of Generation}} \\ \text{minus} \\ \overbrace{\sum_{i,j} R_{i,j}^{GR,f} \times OP_{i,j}^{GR,f} + \sum_{i,j} R_{i,j}^{IL,f} \times OP_{i,j}^{IL,f}}^{\text{Cost of Fast Instantaneous Reserves}} \\ \text{minus} \\ \overbrace{\sum_{i,j} R_{i,j}^{GR,s} \times OP_{i,j}^{GR,s} + \sum_{i,j} R_{i,j}^{IL,s} \times OP_{i,j}^{IL,s}}^{\text{Cost of Sustained Instantaneous Reserves}} \end{array} \right.$
132.	Schedule 13.3, clause 9 – Constraints	The word “generation” is in bold but it is not a defined term in the Code.	In maximising the objective function, the **system operator** must ensure that the following constraints are met to an accuracy specified in the **model formulation**: … (b) each constraint relating to generation set out in clause 9A: …
133.	Schedule 13.3, clause 9A – Constraints relating to generation	Clause 9A(c)(iv) refers to clause 13.141 but this clause was revoked in 2022. The reference is no longer necessary.	The constraints for the purpose of clause 9(b) are that— … (c) the modelling system schedules **electricity** generation for each **intermittent generating station** in a **trading period** at a level that is no higher than the potential output of the **intermittent generating station**, determined as follows: (i) in relation to the **price-responsive schedule**, in accordance with clause 13.58A(1)(aa): (ii) in relation to the **non-response schedule**, in accordance with clause 13.58A(2)(aa): (iii) in relation to the **dispatch schedule**, in accordance with clause 13.71(3): (iv) ~~in relation to the **input information** referred to in clause 13.141, in accordance with clause 13.141(1)(eaa):~~ *[Revoked]* (v) *[Revoked]*
134.	Schedule 13.3, clause 16(1) – Calculation of prices, marginal location factors and reserve prices	The words “reserve prices” are in bold but it is not a defined term.	(1) The modelling system must calculate the following set of prices: … (b) reserve prices for each **island**: …
135.	Schedule 13.3AA, clause 3(1) – Adjusting	The words “Technical Code” are not in bold	(1) As soon as practicable after the **system operator** instructs the **electrical disconnection** of **demand** in accordance with Schedule 8.3,

#	Clause	Issue	Proposed amendment
	expected profile of demand for demand that was unable to be supplied	but this is a defined term.	Technical Code B, clause 6(1)(d) or 6(2)(d), the **system operator** must— …
136.	Schedule 13.4, clause 9(2) – Decision must be recorded	The words "type A co-generating station" should be "type A industrial co-generating station" as this is the defined term. The words "type B co-generating station" should be "type B industrial co-generating station" as this is the defined term.	(2) The register must state, for each approval on the register,— (a) whether the applicant's **generating units** have been approved as a **type A industrial co-generating station** or a **type B industrial co-generating station**; and …
137.	Schedule 13.4, clause 13(2) – Authority may rescind or amend approval	The words "type B co-generating station" should be "type B industrial co-generating station" as this is the defined term.	(2) The **Authority** may, at the request of a **type A co-generator** or a **type B co-generator**, amend an approval to change a **type A industrial co-generating station** to a **type B industrial co-generating station**, or vice-versa.
138.	Schedule 13.5, clause 2(2) – Requirements for design of FTRs	The hyphen in "inter-island" should not be in bold as it is not part of the defined term.	(2) At a minimum, the **FTRs** allocated under the **FTR allocation plan** must be **FTRs** between a **hub** in the South Island and a **hub** in the North Island that would provide a reasonable match with the trading points for exchange–traded futures products or the equivalent **electricity** futures products, and which would enable the volumes of **FTRs** available to reflect inter-**island grid** capacity.
139.	Schedule 13.8	In the heading of the schedule, the abbreviation "cl" should be "cls" for consistency.	**Schedule 13.8** **cls 1.1, 13.3A, 13.3B and 13.3E** **Approval of dispatch-capable load station**
PART 15 – RECONCILIATION			
140.	15.13 – Notice by embedded generators	The words "embedded generation station" should be "embedded generating station" as this is the defined term.	An **embedded generator** must give a notice to the **reconciliation manager** for an **embedded generating station** in relation to a **point of connection** for the purposes of clauses 15.3 and 15.5(3) if the **embedded generator** will not receive payment from the **clearing manager** or any other person for any **electricity** generated by the relevant ~~**embedded generation station**~~ **embedded generating station** through the **point of connection** to which the notice relates.
141.	15.26 – Reconciliation manager to	The words "service provider" are in bold but	… (2) If the **reconciliation manager** considers that information provided by a **reconciliation**

#	Clause	Issue	Proposed amendment
	correct information	this is not a defined term.	**participant** or a service provider under this Part is incorrect, the **reconciliation manager** must refer the issue to the **Authority**, and, if directed by the **Authority** to do so, take all reasonable steps to correct the information. (3) A **reconciliation participant** or service provider must provide any information to the **reconciliation manager** that the **reconciliation manager** requires to correct information under subclause (2). …
142.	Schedule 15.2, clause 11(2)	The word “software” is in bold but it is not a defined term for this part of the Code.	(2) **Raw meter data** obtained by the electronic **interrogation** of a **metering installation** must consist of the following as a minimum: … (e) for all **metering information**, an **interrogation** log generated by the **interrogation** software to record details of all **interrogations**. The **reconciliation participant** responsible for collecting the data must peruse the **interrogation** log and take appropriate action if problems are apparent. Alternatively, this process may be an automated software function that flags exceptions. …
143.	Schedule 15.2, clause 20 – Data transmission	The word “metering” should be in bold as it is a defined term.	Transmissions and transfers of data related to **metering** between **reconciliation participants** or **reconciliation participant’s** agents, for the purposes of this Code, must be carried out electronically, using systems that ensure the security and integrity of the data transmitted and received.
144.	Schedule 15.3, clause 8(4) – Provision of submission information to reconciliation manager	The words “non half-hour metering” should be in bold as it is a defined term.	(4) However, a **reconciliation participant** need not comply with subclause (2) and subclause (3) if— … (b) the approved **profile** allows the **reconciliation participant** to provide **half hour submission information** from a **non half-hour metering installation**; and …
145.	Schedule 15.4, clause 19 - Calculation of unaccounted for electricity	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $AF_{Ri} = \frac{(SC_{Ri} \text{ x } MS_{Ri})}{\text{sum}(SC_{R1} \text{ x } MS_{R1}, \ldots, SC_{Rn} \text{ x } MS_{Rn})}$ $MS_{Ri} = Q_{ICPD\text{-}LA\ Ri} / \text{sum}(Q_{ICPD\text{-}LA\ 1}, \ldots, Q_{ICPD\text{-}LA\ n})$ Updated: $\mathrm{AF}_{Ri} = \frac{(SC_{Ri} \times MS_{Ri})}{\sum_{i=1}^{n} SC_{Ri} \times MS_{R_i}}$ $MS_{Ri} = \frac{Q_{ICPD-LA\ Ri}}{\sum_{i=1}^{n} Q_{ICPD-LA\ Ri}}$

#	Clause	Issue	Proposed amendment
146.	Schedule 15.4, clause 22(b) - Balancing	The formula format has been updated for consistency across the Code and to reflect modern usage. Current and updated formulas are displayed to the right rather than displaying as redlined.	Current: $Q_{BAL\ NSPx\ Ri} = \frac{Q_{ILUN\ NSPx\ Ri}\ \mathrm{x}\ TOT_{ND\ NSPx}}{\mathrm{sum}(Q_{ILUN\ NSPx\ R1}, \ldots, Q_{ILUN\ NSPx\ Rn})}$ Updated: $Q_{BAL\ NSPx\ Ri} = \frac{Q_{ILUN\ NSPx\ Ri} \times TOT_{ND\ NSPx}}{\sum_{i=1}^{n} Q_{ILUN\ NSPx\ Ri}}$
PART 16A – AUDITS			
147.	16A.16 – Costs of audits	This clause implies that the audit may establish whether or not the participant being audited has breached the Code. Only a Rulings Panel is able to determine whether there has been a Code breach. The word "audit" should be in bold as it is a defined term.	… (3) If an **audit** establishes, to the reasonable satisfaction of the **Authority**, that the **participant** that was the subject of the **audit** ~~has~~ may have breached the relevant provisions of this Code (whether or not the **Authority** appoints an investigator to investigate the alleged breach), the cost of the **audit** must be met by,— (a) in respect of an **audit** carried out as a result of the **Authority** initiating the **audit**, the **participant** that was the subject of the **audit** and the **Authority**, in proportions to be determined by the **Authority**: (b) in respect of an **audit** carried out in response to a request to the **Authority** under clause 10.17B(2), 11.11(2), or 15.37C(2), the **participant** that was the subject of the **audit** and the **participant** that requested the **audit**, in proportions to be determined by the **Authority**. (4) If the **audit** establishes, to the reasonable satisfaction of the **Authority**, that the **participant** that was the subject of the **audit** ~~has not~~ does not appear to have breached the relevant provisions of this Code, or if there ~~was~~ may have been a breach but the **Authority** considers it to be minor, the cost of the **audit** must be met by,— (a) in respect of an **audit** carried out as a result of the **Authority** initiating the **audit**, the **Authority**: (b) in respect of an **audit** carried out in response to a request to the **Authority** under clause 10.17B(2), 11.11(2), or 15.37C(2), the **participant** that was the subject of the **audit** and the **participant** that requested the **audit**, in proportions to be determined by the **Authority**. …

Appendix E Format for submissions

Submitter	

Minimum offer price exclusions for tie-breaker solutions

Questions	Comments
Q2.1. Do you support the Authority's proposal to amend the Code to exclude intermittent generators from offering at $0/MWh? Please explain your answer.	
Q2.2. Do you agree the proposed amendment is preferable to the alternative options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q2.3. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

Materially large contracts

Questions	Comments
Q3.1. Do you agree there is an issue with how the current Code recognises the benefits of new generation, most notably for wind and solar, for the purposes of determining whether an arrangement constitutes a MLC? If not, why not?	
Q3.2. Do you favour Option 1, Option 2, or an alternative option? Please explain your answer.	
Q3.3. Do you agree that offsets claimed for new generation should be calculated using prevailing industry standards and methodologies specific to each generation type (eg, wind, solar and geothermal)? If not, please explain your reasons and suggest any alternative approaches.	
Q3.4. Do you agree with allowing generators to choose between median generation and each point in time offsets? If not, please explain your reasons and suggest any alternative approaches.	
Q3.5. Do you agree the proposed amendments are preferable to the alternative options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q3.6. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

Refining hedge disclosure obligations to increase transparency

Questions	Comments
Q4.1. Do you support the Authority's proposal to require disclosure of the generating station? Please explain your answer.	
Q4.2. Can you identify any other way to more easily identify PPAs and differentiate between these and firming contracts without defining PPAs in the Code?	
Q4.3. Do you agree a 10 business day timeframe for submission of information, and the same process requirements as those applying to risk management contracts, should be introduced for novel or other types of contracts? Please explain your answer.	
Q4.4. Do you agree with the proposal to include demand response contracts in the definition of risk management contracts and require disclosure of their key terms (including price and price structure) through the hedge disclosure system? Please explain your reasons and any impacts you foresee.	
Q4.5. Do you agree this proposal would increase confidence in published price information? If not, why not?	
Q4.6. Do you agree the proposed amendment is preferable to the alternative options? If you disagree, please explain your preferred option in terms consistent with	

the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q4.7. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?	

Technical and non-controversial amendments

Only complete this section if you have feedback on any of the technical and non-controversial proposed amendments. Please insert the row number at the top of each submission form.

Appendix D row number:	
Questions	**Comments**
Q5.1. Do you agree the issue identified by the Authority is technical and non-controversial?	
Q5.2. Do you have any feedback on the issue identified?	