Requiring the use of half-hourly data for reconciliation

Consultation paper

10 October 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on a proposal to amend the Electricity Industry Participation Code 2010 (Code) to require half-hour metered electricity quantities to be submitted into the wholesale electricity market's reconciliation process, where this data is available.

The proposal will strengthen price signals and incentives for demand-side flexibility

More than 96% of Installation Control Points (ICPs) across New Zealand currently have a meter that records electricity consumption/generation on a half-hourly basis, providing precise insights into consumer demand. However, electricity retailers can choose not to submit this half-hour metering data into the wholesale reconciliation process. Currently, retailers only submit half-hourly data into the reconciliation process for about half of the premises with capable meters.

When half-hourly metering data is not made available, a consumer's electricity use or generation is apportioned across half hour trading periods in accordance with a deemed profile of consumption (load profile). A load profile reduces the accuracy of wholesale cost allocation and obscures the true cost of electricity consumption during different trading periods, weakening the effectiveness of price signals.

These proposed Code amendments will create stronger incentives on retailers to pass on to their customers price signals that reflect the actual costs of consumption. Consumers would be able to make more informed decisions about consuming (or generating) electricity.

These proposed changes would also improve the accuracy of wholesale market reconciliation and settlement processes by increasing the accuracy of invoicing. Retailers would have greater certainty around their cash flows, reducing their operating costs.

Participants' systems will need to be updated to align with Code amendments

To comply with the proposed Code amendments, retailers, distributors, the reconciliation manager and the registry manager would need to update their systems and processes.

Our estimate of the current value of the proposal's implementation and ongoing costs is approximately $6 million. We are seeking feedback on the reliability of our estimates. Though the benefits of this change are less easily calculated, we anticipate that the potential benefits from promoting demand-side flexibility could be tens of millions of dollars, as well as other benefits resulting from a more efficient reconciliation process.

This proposal complements our other competition and consumer mobility initiatives

As part of the Energy Competition Task Force, in July 2025 the Authority decided to change the industry rules so that by 1 July 2026, large electricity retailers (which includes retailers with more than 5% market share) must:

- offer time-varying pricing plans to consumers for electricity use and supply
- make these plans available on their websites and any electricity plan comparison platform prescribed by the Authority (where the platform is capable of presenting them).

Retailers need half-hourly electricity consumption data to offer effective time-varying pricing plans. This proposal therefore supports requiring large retailers to provide such plans.

We are also progressing a range of initiatives under our consumer mobility programme to enhance choice and affordability, including improving electricity bills and enabling easier plan comparisons.

Requiring half-hour metered electricity quantities to be submitted into the wholesale electricity market's reconciliation process will complement these projects. Together, these initiatives will help deliver a modern, digital and consumer-centric electricity system. Consumers will get a better deal on their electricity because the system is designed to make it easy for them to do so.

We welcome your feedback

The Authority welcomes feedback on the proposed Code amendments in this consultation paper. During the consultation period Authority staff will be available to hold individual and group briefings with interested stakeholders.

Next steps

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

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this paper is to consult with interested parties on a proposal to require half-hour metered electricity quantities to be submitted into the wholesale electricity market's reconciliation process where half-hourly consumption data is available. The Electricity Authority Te Mana Hiko (Authority) wants accurate reconciliation of consumers' electricity use and generation. Metering installations that record electricity flowing into and out of a consumer's premises on a half-hourly basis enable this accuracy.[1]

1.2. Currently half-hour metering installations are installed at over 96% of New Zealand premises. However, electricity retailers can choose not to submit this half-hour metering data into the wholesale reconciliation process. When a retailer makes this choice, a consumer's electricity use or generation is apportioned across half hour trading periods in accordance with a load profile. This is therefore not as accurate.

1.3. The Authority proposes to amend the Electricity Industry Participation Code 2010 (Code) to remove this choice.

1.4. The Code amendment proposal would align electricity retailers, or other providers of services associated with electricity supply, to the true wholesale cost of electricity used by consumers with half-hour metering installations. We believe this would improve the incentive on these electricity traders to encourage consumers to use, or generate, electricity in a way that maximises overall consumer benefit. And overall, this change will promote the efficient operation of New Zealand's electricity industry for the long-term benefit of consumers.

1.5. Section 39(1)(c) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. Section 39(2) of the Act provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statement is set out in section 3 of this paper.

How to make a submission

1.6. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to wholesaleconsultation@ea.govt.nz with "*Consultation Paper—Requiring the use of half-hourly data for reconciliation*" in the subject line.

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

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

[1] A small number of smart meters are non-communicating, meaning they record half-hourly consumption data but do not transmit it automatically. Accordingly, this proposal does not apply to data recorded by these meters.

(a) indicate which part should not be published

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

(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, we will discuss this with you before deciding whether to not publish that part of your submission.

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

When to make a submission

1.11. Please deliver your submission by 5pm on Friday 21 November 2025.

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

Next steps following our consultation

1.13. Following our consultation on this paper, the Authority will consider submissions received and decide whether to proceed with the Code amendment proposal, and if so, whether to proceed with it as proposed or in a different form. Our indicative timing for this decision is April 2026.

1.14. If, after considering submissions, the Authority proceeded with Code amendments based on the proposal in this paper, we propose these amendments would come into effect in late 2026 or early 2027. This would provide a period of approximately 9 to 12 months from our anticipated decision date to when the proposal, or some form of it, became effective.

2. Issues the Authority would like to address

Load profiling is used for wholesale electricity reconciliation

2.1. Prior to 1 April 1999, only large consumers could choose retailers. A consumer's electricity use/generation had to be recorded on a half-hourly basis if that consumer wanted to be supplied by an electricity retailer other than the incumbent retailer in the consumer's geographic region. This was to ensure the consumer's electricity use/generation was accurately reconciled against the incoming retailer's contract(s) for the purchase of wholesale electricity. This reconciliation was (and still is) done on a half-hourly basis, which aligns with the length of a trading period in New Zealand's wholesale electricity market.

2.2. On 1 April 1999, with the introduction of full retail competition in the supply of electricity there was no requirement for smaller business and domestic consumers (known as 'mass-market' customers) to have half-hour meters even though they could switch retailers.[2] The electricity use/generation of these consumers could be reconciled against the incumbent retailer's wholesale electricity supply contract(s) on a half-hourly basis according to a deemed profile of half-hourly consumption. At the time, this 'load profiling' was a much lower cost alternative to half-hour metering, making it commercially viable for electricity retailers to compete for new mass-market customers.

2.3. Load profiling is inherently inaccurate, as it takes the monthly consumption volume and allocates a fraction of that volume to each of the trading periods in the month[3]. This allocation is based on a pre-determined profile and although likely accurate on aggregate, is likely to be inaccurate on an individual ICP basis.

2.4. The use of load profiling in the wholesale electricity market's reconciliation process continues today, more than a quarter of a century after its introduction. The profile most commonly used to reconcile consumers' electricity use/generation is the residual profile shape for a balancing area. This profile is determined by subtracting the following from the half-hour metered quantities of electricity supplied to a balancing area:

(a) any half-hour metered load net of half-hour metered generation within the balancing area

(b) any other load reconciled using a profile other than the balancing area residual profile shape (eg, night store heating load, street lighting, or load that is profiled using statistical sampling).

2.5. **Figure 1** shows an example of a balancing area residual profile shape (shown in green). In this example half-hour metered load net of half-hour metered embedded generation (shown in light blue) is subtracted from the balancing area total, followed by non-half-hour metered load that occurs between 11pm and 7am (shown in dark blue). The night load is allocated into the 16 half-hour trading periods between

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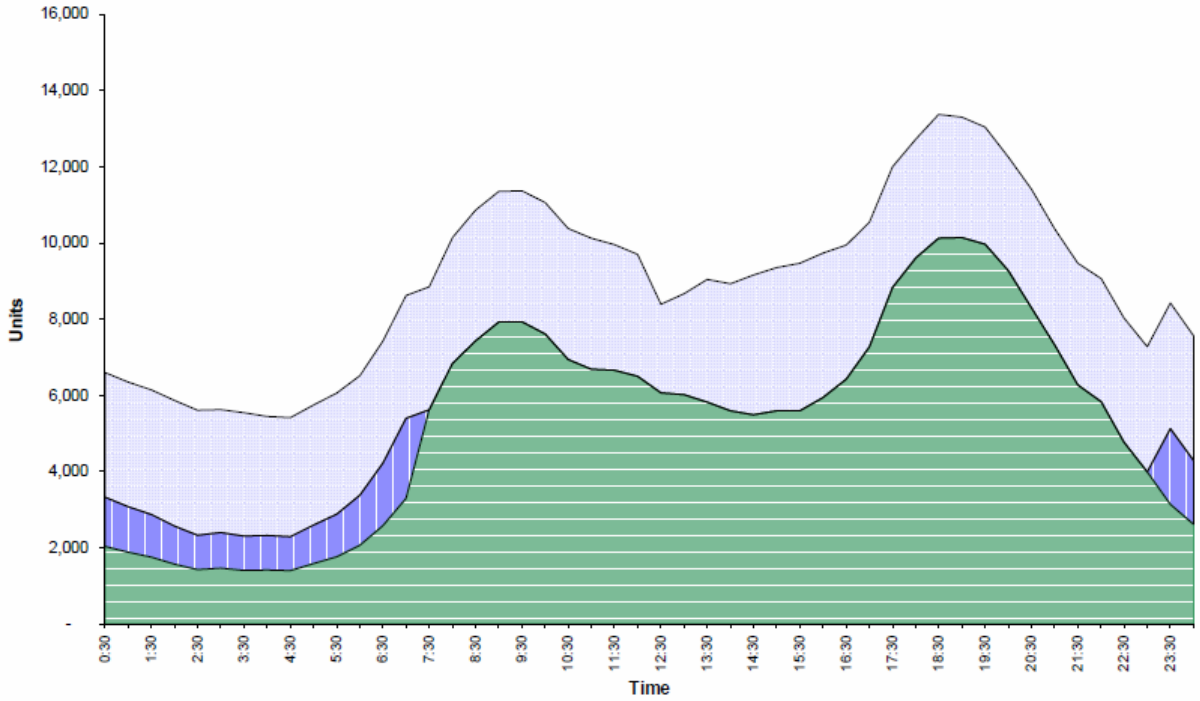
2 These are consumers with a category 1 or category 2 metering installation.

3 There are 1,488 trading periods in a 31-day month, 1,440 in a 30-day month, and 1,344 in a non-leap year February. Additionally, daylight savings adds (April) or subtracts (September) two trading periods.

11pm and 7am using the profile shape that results from subtracting half-hour metered load net of half-hour metered generation from the balancing area total (ie, this profile shape is the line that runs along the base of the area shaded in light blue).

Figure 1: Example of a balancing area residual profile



2.6. If a consumer's profile of electricity consumption differs from the balancing area residual profile shape, in any given half-hour period the consumer's retailer will be assigned an inaccurate amount of wholesale electricity for that consumer. As this inaccurate amount is then used in wholesale electricity market settlement, the retailer is thus not aligned with the true wholesale cost of electricity used by the consumer.

2.7. This also arises with other load profiles permitted to be used in the reconciliation process. It arises with profiles that rely on half-hour metering of a sample set of consumers to generate a profile of consumption for a broader set of consumers (statistically sampled profiles). It can even arise in engineering profiles, which calculate consumption using a detailed knowledge of the operating characteristics of electrical appliances/devices (eg, street lighting).

Unlocking the benefits of half-hourly reconciliation

2.8. The introduction of load profiling in 1999 traded the accuracy of reconciled electricity quantities for greater competition in the supply of electricity to consumers. The competition benefits from using load profiling were considered to outweigh the benefits of accurate half-hourly reconciliation of consumers' electricity use/generation.

2.9. The Authority has formed the view that this is no longer the case. We consider it is not for the long-term benefit of consumers for the wholesale reconciliation process to use load profiling for consumers that have half-hour metering at their premises.

2.10. Currently, electricity retailers can choose whether to submit into the reconciliation process half-hour metered quantities of electricity used or generated by consumers with a half-hour metering installation. If the retailer chooses not to submit half-hour metered quantities for a consumer, that consumer's electricity use/generation is apportioned across half hour trading periods in accordance with a load profile.

2.11. Since the introduction of load profiling 26 years ago, the use of half-hour metering has become widespread in New Zealand as its cost has fallen. Today, over 96% of consumer premises have a metering installation that records electricity flowing into and out of the premises on a half-hourly basis. However, only 45.7% of these premises have their metered quantities submitted into the reconciliation process in half-hourly form.

Demand-side flexibility could be promoted better

2.12. The increasing electrification of New Zealand's economy is expected to require billions of dollars of investment in electricity infrastructure over the coming decades. Given these substantial sums of money, the Authority wants the New Zealand electricity market to incentivise industry participants to offer and promote products and services that enable consumers to act in ways that promote efficient investment in this infrastructure. That is, we want the level of investment to be the outcome of consumers using, and generating, electricity based on prices containing as much relevant information as possible. This includes actual half-hourly electricity use/generation for the large majority of consumers with half-hour metering at their premises.

2.13. The Authority is concerned that not aligning electricity retailers, or other on-sellers of electricity, to the true half-hourly wholesale cost of electricity used by consumers lessens an important incentive on these parties (for the purposes of the proposal in this paper, these parties are collectively referred to as *traders)*.

2.14. This is the incentive to encourage consumers to use, or generate, electricity in a way that maximises overall consumer benefit, particularly through efficient investment in electricity generation and network assets.

2.15. The use of half-hour metered quantities in the reconciliation process would facilitate more cost-reflective settlement than using load profiling, by removing the 'smearing' of electricity consumption across half hour trading periods. Variations in the wholesale cost of electricity used by different consumers would become much clearer.

2.16. We consider this would strengthen the incentive on traders to pass on to their customers at least some of the price effect of this greater cost reflectivity. To not do so increases the possibility of lower cost-to-serve customers moving to a trader offering a product more reflective of the lower wholesale cost of electricity used by these consumers.

2.17. If more consumers faced price signals that better reflected the wholesale cost of electricity purchased on their behalf, we consider their electricity consumption and investment decisions and behaviours would, overall, better support efficient investment in, and operation of, the electricity industry. Consumers would be able to make more informed decisions about consuming (and as applicable generating) electricity.

2.18. For example, a significant amount of the expected electricity generation investment in New Zealand over the coming years and decades (41% of committed capacity) is expected to be in the form of solar photovoltaic generation.[4] This generation produces electricity from a non-storable energy source, the availability of which coincides with electricity demand that is lower than during the morning and evening peak demand periods. This, and the very low marginal cost of solar photovoltaic generation, might be expected to result in wholesale electricity prices during the middle of the day being lower than during the two daily peak demand periods.

2.19. Traders passing on to their customers at least a portion of these lower wholesale electricity prices would incentivise consumers to use relatively more electricity during the day, rather than during the morning and evening peak demand periods. This would have the twin advantages of using electricity network infrastructure more efficiently, and reducing the need to store some of the electricity produced during the day for use at peak times.

2.20. At the same time, relatively higher prices during peak demand periods would incentivise consumers to use relatively less electricity during these periods. Reducing peak electricity demand[5] would lessen the need for investment in electricity generation and transportation assets that are used for relatively short periods of time to meet this peak demand. An example of how peak demand reduction has been done for many decades in New Zealand is consumers giving permission for hot water cylinders to be switched off during periods of high electricity demand (known as ripple control). Today new and evolving technologies are providing additional ways for consumers to reduce their peak electricity demand. For example, an in-home battery energy storage system that is charged during off-peak periods can be used to supply some or all of a consumer's electricity needs during the consumer's peak demand periods.

2.21. Consumers changing how much electricity they use in total, or when they use electricity, is known as demand-side flexibility. Demand-side flexibility can be achieved through various means, including:

(a) consumer devices controlled by consumers, or by others acting on behalf of consumers (eg, smart appliances, electric vehicle chargers, in-home battery energy storage systems)

(b) consumer devices controlled only by others, with the permission of consumers (eg, hot water heating ripple control)

(c) generation installed at a consumer's premises (eg, solar photovoltaic generation that injects into the distribution network only when network conditions permit,[6] solar photovoltaic generation that charges an in-home battery energy storage system which is then discharged during peak electricity demand periods).

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4 The latest Electricity Demand and Generation Scenarios published by the Ministry of Business, Innovation and Employment in July 2024 project solar photovoltaic generation capacity to grow from 0.4 gigawatts (GW) to 2.7–9.1GW in 2050.

5 Either in absolute terms or in terms of a slower rate of growth in peak demand.

6 For example, when the network voltage is within the lawfully permitted range.

2.22. The Authority sees the use of half-hour metered quantities in the wholesale reconciliation process as an important means by which to incentivise demand-side flexibility. As the Market Development Advisory Group explained:[7]

> *In order for a (trader) to get value from (demand-side flexibility), there are two key variables:*
>
> *(a) To reduce its reconciled volumes in periods where the wholesale price is higher than its retail tariff*
>
> *(b) To reduce demand from its customers sufficiently to reduce the wholesale price at that point in time.*
>
> *A (trader) who is submitting half hourly metered quantities for reconciliation will be able to capture the full value of both (a) and (b), as the response of its customers in the particular periods of high wholesale prices will be rewarded at that price. However, if the (trader) is only submitting monthly metered quantities, and having a half-hourly shape created through a profile, customer demand response in any particular half hour will effectively be "smeared" across the month according to the profile, and the benefits accruing to the (trader) (and thus the customers) will be a fraction of that achieved within the half hours when it was executed. This will significantly dilute the incentives for the (trader) to utilise (demand-side flexibility).*

2.23. For the reasons discussed above, the Authority considers that requiring the submission of half-hour metered quantities for wholesale reconciliation would help incentivise the use of demand-side flexibility. This in turn would promote efficient investment in electricity industry infrastructure needed as New Zealand's economy becomes more electrified. Consumers would benefit from this through electricity bills that should be lower than they otherwise would be.

2.24. A cost-benefit analysis of distributed energy resources in New Zealand, undertaken for the Authority in 2021, estimated that the unfettered potential of distributed energy resources to offset new electricity generation and network infrastructure until 2050 exceeds $6 billion in net present value terms.[8] Accurate data for reconciliation is an important component in maximising these possible benefits.

The reconciliation process also contains unnecessary inefficiencies

2.25. The Authority is also concerned that continuing to use load profiling for a substantial amount of the electricity consumption quantities submitted into the reconciliation process creates unnecessary inefficiencies in the process.

2.26. First, the quantum of unaccounted-for-energy in a trading period is higher than it needs to be, due to the inherent inaccuracy of profiled electricity quantities relative to half-hour metered electricity quantities. This reduces the accuracy of wholesale invoicing and in turn consumer invoicing.

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7 Market Development Advisory Group, 6 December 2022, Price discovery in a renewables-based electricity system – Library of options, p. 31, available at Electricity Authority | MDAG options for price discovery in a renewables-based electricity system.

8 See Reeve, D., Stevenson, T., & Comendant, C., 7 July 2021 updated 13 September 2021, Cost-benefit analysis of distributed energy resources in New Zealand, A report for the Electricity Authority, p. 25.

2.27. Second, the profiling of half-hour metered reconciliation quantities means the electricity quantities in the three settlement wash-ups are more uncertain than they need to be.[9] This results in:

(a) more settlement wash-ups than are necessary

(b) traders facing more uncertainty around their cash flows, which increases their operating costs.

Why the Authority is addressing this issue now

2.28. The Authority is addressing the accuracy of wholesale market reconciliation and settlement now for several reasons.

2.29. **Over 96% of consumer installations have a metering installation that records electricity consumption/generation on a half-hourly basis.**[10] Although the rollout of smart meters began two decades ago,[11] the proportion of ICPs with half-hourly data submitted for reconciliation has only increased from 20% to 45.7% over the past 10 years.

2.30. The Authority's view is that continuing with the status quo is unlikely to ensure that all premises with half-hourly metering will have their data included in the reconciliation process within the same timeframe proposed under the Code amendment.

2.31. Given the widespread availability of half-hourly metering data, the Authority also considers it an appropriate time to reassess whether load profiling remains a necessary or effective low-cost method for enabling electricity retailers to compete to supply these consumers.

2.32. **Our proposal is consistent with recommendations made by two of our former advisory groups** — the Innovation and Participation Advisory Group (IPAG) and the Market Development Advisory Group (MDAG).

2.33. IPAG recommended setting a profiling sunset date at which half-hourly reconciliation became mandatory for all sites capable of half-hourly reconciliation (ie, half-hour metered sites). IPAG suggested this could also be achieved using a sinking cap on the percentage of a participant's half-hour metered sites reconciled by load profile.[12]

2.34. MDAG also recommended a sunset date on the use of load profiling for those ICPs with the capability to measure half-hourly data.[13] MDAG consulted publicly on this

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9 Currently, the Code provides for settlement wash-ups to occur three, seven and 14 months after the initial reconciliation run.

10 As at 30 September 2025.

11 Meridian Energy undertook a pilot rollout of smart metering to 6,000 businesses and households in mainly rural Central Hawkes Bay in 2005–2006, and soon after began rolling out smart meters to approximately 110,000 customers in Christchurch.

12 Innovation and Participation Advisory Group, 4 December 2019 (updated July 2021), Advice on reducing barriers to customer access to multiple electricity services, p. 31, available at Electricity Authority I IPAG advice on reducing barriers to customer access to multiple electricity services.

13 Market Development Advisory Group, 11 December 2023, Price discovery in a renewables-based electricity system – Final recommendations paper, p. 100, available at Electricity Authority I MDAG final recommendations on price discovery in a renewables-based electricity system.

recommendation, with almost all submissions on the recommendation supporting its implementation.[14] One submitter noted the relevance of ICP-level metering data may decrease over time as electricity is able to be metered at the appliance level.[15]

2.35. **The proposal supports new technologies in the electricity market** and is consistent with initiatives overseas. New and evolving technologies are increasingly being used in New Zealand's electricity industry, as the cost of these technologies falls. The Authority wants the design of the wholesale electricity market to support the uptake of these technologies.

2.36. Great Britain is currently implementing market-wide half-hourly settlement, which involves the introduction of site-specific reconciliation using half-hour meter readings. The outcome expected from market-wide half-hourly settlement is a faster, more accurate settlement process.[16]

2.37. The energy regulator for Great Britain, the Office of Gas and Electricity Markets, has estimated that market-wide half-hourly settlement will deliver net benefits to Great Britain energy consumers of between £1.5 billion and £4.5 billion by 2045.[17]

2.38. In Australia, the energy markets rule maker, the Australian Energy Market Commission, has recently made rules that are intended to achieve universal uptake of smart meters in the Australian National Electricity Market by 2030.[18]

2.39. One of the practical effects of this rule will be universal submission, for reconciliation, of metering quantities with an interval of 30 minutes or less. Moreover, these metering quantities will be at the meter register level, since the Australian Energy Market Operator requires access to active and reactive register level metering data.[19]

This proposal complements our other competition and consumer mobility initiatives

2.40. Requiring half-hour metered electricity quantities to be submitted into the wholesale electricity market's reconciliation process (where this data is available) supports the Authority's decision in July 2025 to require large electricity retailers to offer time-varying pricing plans to consumers from 1 July 2026. This decision was part of the Energy Competition Task Force work programme.[20]

Market Development Advisory Group, 6 December 2022, Price discovery in a renewables-based electricity system – Library of options, pp. 31–33, available at Electricity Authority I MDAG options for price discovery in a renewables-based electricity system.

14 See the submissions of 2degrees, Contact Energy, Electric Kiwi, Flick Electric, Genesis Energy, Haast Energy Trading, Meridian Energy, and Pulse Energy.

15 SolarZero, 6 March 2023, MDAG Report – Price discovery in a renewables-based electricity system, p. 3, available at Electricity Authority I SolarZero submission on MDAG options paper.

16 See MHHS programme.

17 *Ibid*

18 Australian Energy Market Commission, 28 November 2024, National Electricity Amendment (Accelerating Smart Meter Deployment) Rule I National Energy Retail Amendment (Accelerating Smart Meter Deployment) Rule, available at AEMC I Rule changes I Accelerating smart meter deployment.

19 Australian Energy Market Operator, 14 October 2019, Five Minute & Global Settlement – Metering Procedure Changes (Package 2) Final Determination, p. 7, available at AEMO I Five Minute & Global Settlement – Metering Procedure Changes (Package 2) Final Determination.

20 2BC_Improving_pricing_plan_options_for_consumers.pdf

2.41. To enable effective time-varying pricing plans, retailers require access to half-hourly electricity consumption data. This proposal supports requiring large retailers to offer such plans.

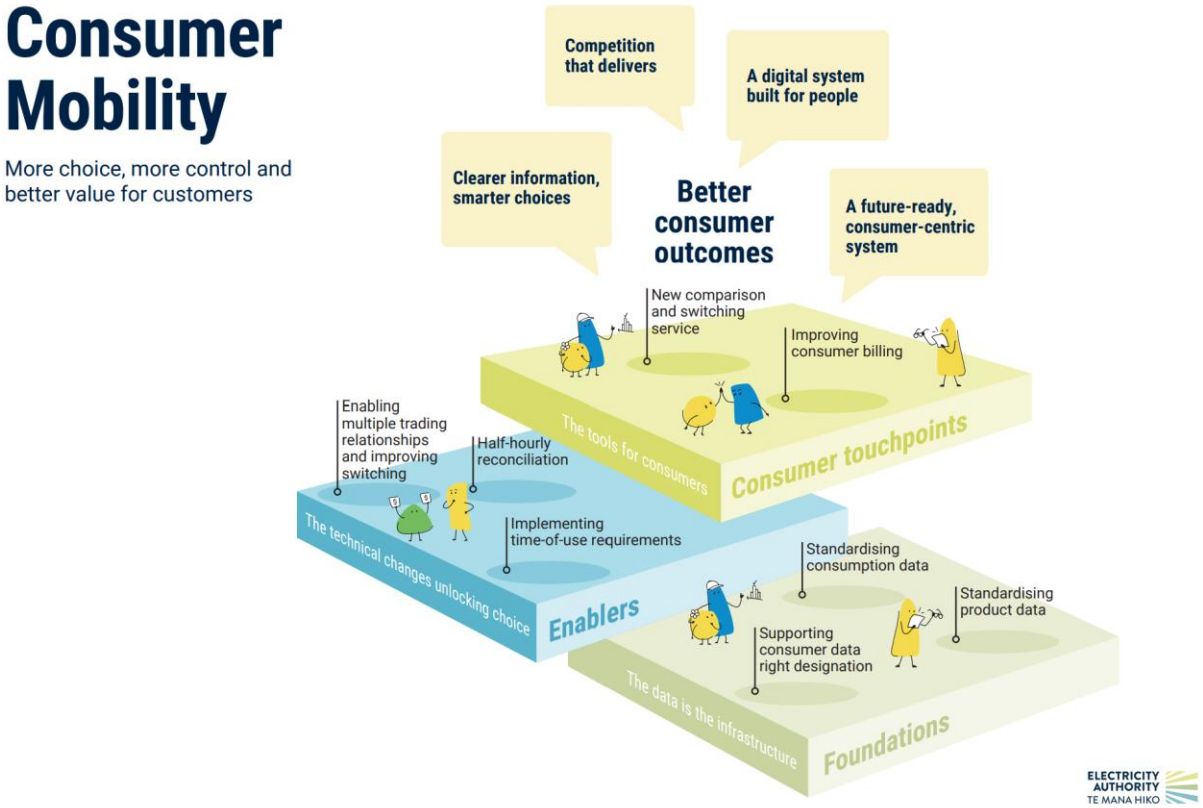
2.42. This proposal also supports the Authority's consumer mobility work programme to improve choice and affordability for consumers, which include:

(a) **Improving electricity bills** — considering options to provide better information to consumers and encourage them to compare and switch (consultation in October 2025)

(b) **Improved comparison and switching** — we are funding an improved comparison and switching service to make it easier for consumers to find the best deal for their circumstances (new service due to begin in early 2026)

(c) **Enabling multiple trader relationships** — proposing changes to enable consumers to choose different retailers to buy from or sell to for electricity consumption and generation (consultation closed in July 2025)

(d) **Improving the accessibility of electricity data** — standardising and streamlining access to electricity product and consumption data in alignment with the proposed consumer data right for electricity to enhance comparison and switching services and support new products (consultation closed on product data standards in August 2025).



2.43. Together, these initiatives will help create a modern, digital, and consumer-focused electricity system — one that makes it easy for consumers to find the best deal.

The Authority proposes amending the Code to require half-hourly data for reconciliation

2.44. The Authority proposes amending the Code to require electricity traders to submit for reconciliation, as half-hourly volumes per ICP, the electricity consumption/ generation of all their half-hour metered customers.

2.45. While the trader would have the obligation, the trader could contract a third party (eg, a metering equipment provider) to submit the half-hour metered quantities on the trader's behalf. This may be more efficient than the trader submitting the data itself.

2.46. The reconciliation manager, being the market operation service provider responsible for wholesale electricity market reconciliation services, would then aggregate this information to the following levels:[21]

(a) NSP code

(b) reconciliation type[22]

(c) profile[23]

(d) loss category code

(e) flow direction (ie, electricity flowing from an electricity network to an ICP or electricity flowing from an ICP to an electricity network)

(f) dedicated NSP[24]

(g) trading period.

2.47. The Authority proposes to replace the reconciliation manager's scaling of traders' submission information using the 'ICP days' scaling factor[25] with the reconciliation manager validating traders' submission information against the number of days a trader is recorded in the registry as supplying an ICP that is active. For any discrepancies between the submission information and the registry's information, the reconciliation manager would apply a default volume based on the highest metering category at the ICP. The proposed default volumes, which the Authority considers to be a reasonable representation of consumption for each metering category, are as follows:

(a) 25 kWh per ICP day, in respect of ICPs with no half-hour metering

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21 See clause 8(6) of Schedule 15.3 of the Code.

22 'Reconciliation type' indicates either the type of electricity network the reconciliation quantities relate to (eg, embedded network, local network), or the type of reconciliation processing to be undertaken (eg, transmission grid point of connection, transmission-connected consumer, transmission-connected generator).

23 Half-hour metered reconciliation quantities are given a profile code of 'HHR', to indicate that no load profile is to be applied to them.

24 This identifies when an ICP cannot be allocated to a different NSP during an outage.

25 The Code defines an 'ICP day' to mean any day when an ICP with either load or both load and generation is recorded in the registry of ICPs as being 'Active' (ie, consuming electricity or both consuming and generating electricity). The 'ICP days' scaling factor represents the ratio of the number of ICP days for a trader as reported by the registry manager over the number of ICP days reported by the trader in its reconciliation submission information. The ICP days scaling factor is always 1 for consumers directly connected to the transmission grid. See clause 7 of Schedule 15.4 of the Code.

(b) 0.5 kWh per trading period per ICP day, in respect of ICPs with a category 1 metering installation that is a half-hour metering installation

(c) 2 kWh per trading period per ICP day, in respect of ICPs with a category 2 metering installation that is a half-hour metering installation

(d) 40 kWh per trading period per ICP day, in respect of ICPs with a category 3 metering installation

(e) 100 kWh per trading period per ICP day, in respect of ICPs with a category 4 or higher metering installation.

2.48. This proposed arrangement removes the main reason for using the ICP days scaling factor, which is to address the possibility of unaccounted-for-energy caused by traders' submission information missing ICPs and/or days when electricity is being used, or used and generated, at an ICP. Given this, the Authority proposes to remove the ICP days scaling factor process from the Code. We consider this will reduce operating costs for the electricity industry.

2.49. Consistent with moving to a wholesale reconciliation process that relies primarily on half-hour metered quantities, we propose only the Authority be permitted to create new load profiles for non-half-hour metered electricity quantities. Existing load profiles for half-hour metered quantities that do not have ICPs assigned to them would be removed. Reconciliation participants would be permitted to create new load profiles for unmetered electricity consumption only (eg, street lighting).

2.50. Recognising that half-hour metered quantities would comprise a very high percentage of total reconciliation quantities, the Authority proposes to bring forward, by one business day, the deadline for reconciliation data to be provided to the reconciliation manager.[26] This recognises the additional time required by the reconciliation manager to process the much larger data volumes. The Authority considers that bringing forward the deadline by one business day should not be onerous for reconciliation participants because they would be receiving metering data on a daily, or near daily, basis for the overwhelming majority of the ICPs they supply.

2.51. The Authority also proposes to remove the following obligations on reconciliation participants:

(a) The obligation on a reconciliation participant to report to the Authority each month the percentage, in relation to each NSP, of the ICPs from which consumption information was collected and reported into the reconciliation process in the previous 12-month period.[27] Instead this percentage would be included in the participant's periodic reconciliation audit.

(b) The obligation on a reconciliation participant to report to the Authority each month the percentage, in relation to each NSP, of the ICPs from which consumption information was collected and reported into the reconciliation

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26 Ie, we propose the deadline would be 1600 hours on the 3rd business day of each calendar month, rather than 1600 hours on the 4th business day.

27 See clause 8(1)(a)–(b) of Schedule 15.2 of the Code.

process in the previous four-month period.[28] Instead this percentage would be included in the participant's periodic reconciliation audit.

(c) The obligation on a reconciliation participant to report to the Authority each month and on a rolling four-monthly basis the percentage of non-half-hour metered interrogations within that period.[29] This percentage would still be monitored in the participant's periodic reconciliation audit.

2.52. In addition, the Authority proposes to:

(a) remove the three-month reconciliation revision

(b) bring forward the seven-month reconciliation revision to be a five-month revision

(c) bring forward the 14-month reconciliation revision to be a 13-month revision.

2.53. Several consequential amendments to the Code would result from these proposed changes to the reconciliation revisions:

(a) the reconciliation manager would not recalculate the seasonal adjustment shape after the month 5 revision, unless doing so was necessary to resolve a dispute under clauses 14.25 or 15.29 of the Code, or to correct information under clauses 15.21 to 15.26 of the Code[30]

(b) the existing transitional provisions concerning reconciliation revisions would be updated[31]

(c) reconciliation participants would have to replace volume information created using estimated readings with volume information created using validated meter readings no later than the month 13 revision[32]

(d) the proportion of submission information that is comprised of historical estimates would have to be at least 90% for revised data provided at the month 5 revision[33]

(e) the proportion of submission information that is comprised of historical estimates would have to be 100% for revised data provided at the month 13 revision.[34]

2.54. Consistent with improving the accuracy of the electricity quantities assigned to individual consumers, the Authority proposes to add a Code provision for meter readings provided by customers to have appropriate validation (eg, a time-stamped photo of the meter reading).

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28 See clause 9(1)(a)–(b) of Schedule 15.2 of the Code.

29 See clause 9(3) of Schedule 15.2 of the Code.

30 See clause 15.19(3)(d)–(4) of the Code.

31 See clause 15.28 of the Code.

32 See clause 4(2) of Schedule 15.2 of the Code.

33 See clause 10(3) of Schedule 15.3 of the Code.

34 *Ibid*

2.55. Lastly, the Authority proposes to remove from Part 15, and the remainder of the Code, all references to interim certified metering installations. This is because interim certification ended on 1 April 2015.

Q1. Do you agree the issue identified by the Authority is worthy of attention?

3. Regulatory statement for the proposed amendment

Objective of the Code amendment proposal

3.1. The Code amendment proposal's objective is to promote the efficient operation of the electricity industry by improving the accuracy of the wholesale electricity market's reconciliation of consumers' electricity use and generation.

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

The draft Code for the Code amendment proposal

3.2. The draft Code for the Code amendment proposal is contained in Appendix A.

The Code amendment proposal's benefits and costs

3.3. The Authority has evaluated the benefits and costs of the Code amendment proposal.

The Code amendment proposal's expected benefits

3.4. The Authority considers the main benefit of the Code amendment proposal would be promoting efficient investment in, and operation of, electricity generation and network infrastructure.

3.5. Under the proposal, reconciled quantities allocated to traders by the reconciliation manager would more accurately reflect actual quantities used/generated by traders' customers during each half-hour trading period. For half-hour metered consumers, electricity use/generation would be allocated to the correct half-hour trading period rather than being allocated to a trading period based on a load profile that does not reflect their half-hourly consumption/generation profile. For non-half-hour metered consumers whose consumption/generation is allocated to trading periods using the balancing area residual load profile shape, this profile would become more reflective of their electricity use/generation.

3.6. As discussed above, if traders' wholesale electricity bills more closely reflect the actual wholesale cost of electricity used by their customers, then traders have more of an incentive to offer and promote products and services that encourage demand-side flexibility. Demand-side flexibility is expected to have a significant benefit over the coming years and decades due to the electrification of New Zealand's economy.

3.7. As noted in paragraph 2.23, a cost-benefit analysis of distributed energy resources in New Zealand, undertaken for the Authority in 2021, estimated that the unfettered potential of distributed energy resources to offset new electricity generation and network infrastructure until 2050 exceeds $6 billion in net present value terms.[35] Similarly a 2022 report, commissioned by several electricity generator/retailers and electricity distributors, estimated that a more flexible electricity system incorporating

[35] See Reeve, D., Stevenson, T., & Comendant, C., 7 July 2021 updated 13 September 2021, Cost-benefit analysis of distributed energy resources in New Zealand, A report for the Electricity Authority, p. 25.

demand response, smart electric vehicle charging and distributed energy resources will save around $10 billion on a net present value basis to 2050.[36]

3.8. It is difficult to say how much of the potential benefit of demand-side flexibility will be realised over the next 25 years. It is also difficult to say what percentage of this potential benefit would be due to the Code amendment proposal proceeding. However, the Authority considers the Code amendment proposal's potential benefit from promoting demand-side flexibility could easily be many millions of dollars. For example, if the increased demand-side flexibility under the proposal were to achieve just 0.5% of the potential benefit estimated in the 2021 and 2022 analyses, the proposal would deliver an estimated $30–$50 million in present value benefits.

3.9. In addition to this primary benefit, the Authority considers the Code amendment proposal would have several other benefits.

3.10. The amount of unaccounted-for-energy would fall as reconciled quantities allocated to traders by the reconciliation manager more accurately reflected actual quantities consumed by traders' customers in each trading period. This would enable more accurate invoicing of traders and in turn more accurate invoicing of consumers. Improving the accuracy of consumer invoicing would bring the marginal value consumers place on the electricity they buy closer to the cost of producing that electricity. This would improve the efficiency of the electricity industry by delivering an allocative efficiency benefit. Allocative efficiency is achieved when the marginal value consumers place on a product or service equals the cost of producing that product/service, so that the total of individuals' welfare in the economy is maximised.

3.11. The Authority considers the use of half-hour metered quantities in the reconciliation process would deliver operational efficiencies for the electricity industry, by enabling the removal of one of the three settlement wash-ups required under the Code. Currently, these wash-ups occur three, seven and 14 months after the initial reconciliation run. We consider the improved accuracy of electricity quantities submitted into the wholesale reconciliation process would, in due course, remove the need for the month three wash-up. This would have operational cost savings for reconciliation participants and the reconciliation manager.

3.12. We also consider the improved accuracy of electricity quantities submitted into the wholesale reconciliation process would enable the month seven wash-up to be brought forward — say, to month five. We believe it may also be possible to bring forward the month 14 wash-up, to be a month 13 wash-up. Bringing forward these wash-ups would reduce the amount of uncertainty traders face in relation to their cash flows, which could help reduce their operating costs.

3.13. A further benefit of the Code amendment proposal would be removing the siloing of metering information by reconciliation participants. Receiving disaggregated half-hour metered quantities would enable the reconciliation manager to undertake some metering data validation that cannot be done by individual traders. For example, this could be a further check for omissions/duplications in the data. For consumers who have changed the electricity retailer at their premises, the

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[36] See Boston Consulting Group, October 2022, The Future is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 11.

reconciliation manager would be able to compare submitted quantities against historical quantities. The relevant traders could be advised of any material discrepancies.

3.14. The Code amendment proposal also offers an opportunity to begin simplifying reconciliation-related processes undertaken by the electricity industry. This option could be a step towards one industry participant — the reconciliation manager — aggregating all metered, and possibly all non-metered, electricity quantities for the purposes of wholesale reconciliation. The Authority expects one entity undertaking this aggregation function, rather than more than 50, would lower overall operating costs for the electricity industry (eg, reduced software costs and data auditing costs).

3.15. Having only the reconciliation manager aggregate electricity quantities for reconciliation might also be expected to provide a lower cost means of giving effect to future changes in New Zealand's distribution networks. For example, the decentralisation of the electricity industry, including increasing amounts of embedded/distributed generation and energy storage systems, might be expected to result in changes to distribution network losses. This would necessitate changes to existing distribution loss factors, and possibly more loss factors. It would be more efficient and lower cost for the reconciliation manager to apply additional loss factors than for this to be done by multiple traders.

The Code amendment proposal's expected costs

3.16. The Authority considers industry participants would incur both implementation and ongoing operating costs under the Code amendment proposal.

Implementation costs

3.17. The Code amendment proposal would be a material change to the wholesale electricity reconciliation process. The Authority expects the implementation costs of the proposal would also be material.

3.18. To minimise changes to systems and processes, the Authority proposes the following implementation approach:

(a) Traders would continue to upload reconciliation data via secure file transfer protocol (SFTP) on a monthly basis.

(b) Traders would submit one submission file per local network,[37] with this file containing all individual lines of data per ICP supplied by the trader.

(c) Traders would be able to choose whether to submit one submission file:

(i) for *all* embedded networks on which they supply customers, or

(i) for *each* embedded network on which they supply customers.

3.19. We welcome feedback on this proposed 'minimum change' approach.

Q3. Do you agree with the Authority's 'minimum change' implementation approach?

[37] Ie, a network with a point of connection to the transmission grid.

3.20. The Authority estimates that changing the reconciliation manager's systems and processes to accommodate the Code amendment proposal would have an implementation cost of approximately $200,000–$300,000. This cost would relate primarily to loss adjusting and then aggregating half-hour metered quantities, and handling and storing significantly more data than under the status quo.[38]

3.21. No material changes to the registry are expected. Its current reporting processes are sufficient to meet the proposed amendment provided a minor change to its report delivery date (ie, business day four to business day three). Associated implementation costs are not expected.

3.22. The Authority considers it likely that most, if not all, traders would incur some cost to change their systems to provide disaggregated half-hour metering quantities to the reconciliation manager for all their half-hour metered customers. We also expect that there would be some incremental cost associated with implementing the capability to transfer an order-of-magnitude more data to the reconciliation manager.[39]

3.23. For the purposes of assessing the proposal's costs, we have assumed that traders would themselves submit disaggregated half-hour metering quantities to the reconciliation manager. However, some traders may outsource this responsibility to their metering equipment provider(s). We note traders may or may not incur incremental costs in addition to metering equipment providers under this outsourcing arrangement (eg, costs related to metering equipment provider reports to the retailer).

3.24. In mid-2024 the Authority received, from 10 retailers, indicative cost estimates for meeting monthly retail market data reporting requirements. These estimates helped inform our decision to require mandatory monthly reporting on domestic and small business customers by retailers supplying more than 1,000 ICPs.[40]

3.25. The indicative per-retailer cost estimate for implementing the monthly retail data reporting ranged from $20,000 to $550,000.[41] For some retailers a significant component of their estimated cost was providing disaggregated half-hour metered quantities to the Authority.

3.26. We have therefore used these cost estimates to inform our assessment of expected costs under the Code amendment proposal. We consider traders supplying more than 1,000 ICPs would not incur the full amount of the costs included in the above estimates. This is because these estimates include costs that relate to providing the

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38 It may be more cost-effective for the reconciliation manager to store reconciliation data in a cloud-based solution rather than on premises.

39 Using 31 May 2025 figures:

- the electricity consumption of approximately 2.3 million consumers multiplied by an average of 30 days per month, multiplied by 48 trading periods per day, would equate to approximately 3.3 billion lines of data per month (approximately 10 gigabits of data per reconciliation run), and
- the electricity generation of approximately 77,000 consumers multiplied by an average of 30 days per month, multiplied by 48 trading periods per day, would equate to approximately 110 million lines of data per month (approximately 0.33 gigabits of data per reconciliation run).

40 See Electricity Authority, 17 March 2025, Retail market monitoring clause 2.15 information notice – Decision paper, available at Electricity Authority | Improving retail market monitoring - Decision paper.

41 See Appendix G of the Authority's 1 October 2024 consultation paper on the retail market monitoring clause 2.15 information notice, p. 23, available at Appendix G - Assessment of likely costs and benefits.

Authority with retail market data other than disaggregated half-hour metered quantities. Also, we expect some of the costs related to providing disaggregated half-hour metered quantities would not be re-incurred under the Code amendment proposal (eg, data storage costs).

3.27. We note that the Code amendment proposal would require retailers to use a different interface to provide disaggregated half-hour metered quantities to the reconciliation manager, compared to the interface used to provide this data to the Authority. However, we expect the incremental cost of this would be significantly less than the cost reductions described in the preceding paragraph. This is because of our proposed approach of minimising changes to systems and processes, as set out in paragraph 3.18.

3.28. Based on the above considerations, the Authority estimates that the implementation cost for traders under the Code amendment proposal would be approximately 50% of the estimated cost to implement the retail data reporting obligations referred to at paragraph 3.25. This gives an estimated aggregate implementation cost of approximately $1.7 million for the 14 largest traders.

3.29. The Authority considers it reasonable to assume that, under the Code amendment proposal, the implementation costs faced by traders supplying 1,000 ICPs or fewer would be at the lower end of the range of costs for the 14 largest traders. This is because the retail data reporting cost estimates we received from 10 of these 14 traders were much higher for the larger traders than for the smaller traders.[42] To this end, for the 12 traders supplying more than 20 ICPs but no more than 1,000 ICPs, we have applied a 50% discount to the median (rather than mean) implementation cost estimate used for the retail data reporting cost-benefit assessment. This gives an estimated implementation cost of approximately $900,000 for these 12 traders in aggregate.

3.30. On that basis, for the purposes of our assessment of the Code amendment proposal's benefits and costs, the Authority has used an implementation cost point estimate of $3 million. This provides an allowance for some implementation costs to be incurred by traders supplying 20 or fewer ICPs.[43]

Ongoing costs

3.31. The Authority considers the incremental ongoing costs associated with the Code amendment proposal should largely relate to the transfer of larger volumes of half-hour metered data between traders and the reconciliation manager. These ongoing costs would relate to telecommunications bandwidth, data storage (other than for the 14 largest traders), and software licences.

3.32. We estimate ongoing costs for the reconciliation manager would be approximately $25,000 to $50,000 per annum. No ongoing costs for the registry manager are expected.

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42 *Ibid.*

43 As at 30 June 2025, 16 traders supplied between 1 and 9 ICPs. See Electricity Authority | EMI | retail dashboards | Market share.

3.33. The per-retailer estimate for annual ongoing costs under the retail data reporting ranged from $0 to $100,000, with the high-cost estimates relating to the large retailers. The mean and median estimate in the first year of retail data reporting was approximately $38,500 and $32,500 respectively, with this falling to $24,600 and $5,000 respectively thereafter.[44]

3.34. As for implementation costs, for the 14 largest traders we have used an estimate of 50% of the mean ongoing costs for the retail data reporting. Again, this reflects the incremental ongoing costs for these parties under the Code amendment proposal being a fraction of the estimated incremental ongoing costs they face with the retail data reporting. To enable a comparison with the estimated demand-side flexibility benefits discussed above, we have used a discount period of 25 years. The present value of ongoing costs for these 14 traders under the Code amendment proposal is approximately $2.1 million over this period.[45]

3.35. For the same reasons given in our estimation of implementation costs, for traders supplying 1,000 ICPs or fewer under the Code amendment proposal we have applied a 50% discount to the median (rather than mean) ongoing cost estimate used for the retail data reporting cost-benefit assessment. This gives a present value of ongoing costs for these 12 traders of approximately $670,000 over a 25-year period.

3.36. For the purposes of our assessment of the Code amendment proposal's benefits and costs, the Authority has used an ongoing cost point estimate of $3.35 million. This provides an allowance for some ongoing costs to be incurred by traders supplying 20 or fewer ICPs.[46]

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

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

3.38. Our point estimate of the present value of the proposal's implementation and ongoing costs is approximately $6 million. We consider it reasonable to expect the demand-side flexibility benefits of the proposal would exceed this amount over the same period.

3.39. As discussed in paragraphs 3.6 to 3.8, demand-side flexibility is expected to have a significant benefit over the coming years and decades due to the electrification of New Zealand's economy. To deliver a net benefit, the proposal needs to increase demand-side flexibility sufficiently to achieve just 0.1% of the mean of the potential benefit estimated in the two analyses referred to in paragraph 3.7. For the reasons discussed in paragraphs 2.12–2.23, the Authority considers the proposal would incentivise traders to offer and promote products and services that encourage this level of demand-side flexibility.

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44 See Appendix G of the Authority's 1 October 2024 consultation paper on the retail market monitoring clause 2.15 information notice, p. 23, available at Appendix G - Assessment of likely costs and benefits.

45 Using an annual discount rate of seven percent.

46 As at 30 June 2025, 16 traders supplied between 1 and 9 ICPs. See Electricity Authority | EMI | retail dashboards | Market share.

Q4. Do you agree the Authority has correctly identified the benefits and costs of the proposed amendment?

Q5. Do you agree the benefits of the proposed amendment outweigh its costs?

The Authority has identified alternative options for addressing the objective

3.40. The Authority has identified two other ways of addressing the Code amendment proposal's objective:

(a) Rely on status quo arrangements.

(b) Require electricity traders to submit into the reconciliation process, as aggregated half-hourly quantities, the electricity consumption/generation of half-hour metered consumers.

Rely on status quo arrangements

3.41. The first alternative way of addressing the Code amendment proposal's objective is to rely on status quo arrangements.

3.42. This alternative relies on competition in the supply of electricity and associated services to incentivise traders to submit half-hour metered quantities into the wholesale reconciliation process. In particular, it relies on competition incentivising traders to submit half-hour metered quantities for reconciliation where this results in lower energy costs for the trader than applying a load profile. This results in electricity consumption/generation settled on the balancing area residual profile shape becoming relatively more expensive, which in turn incentivises traders to submit half-hour metered quantities for more ICPs into the reconciliation process.

3.43. The Authority considers the main benefit of relying on the status quo would be delaying the incremental implementation and operating costs expected under the Code amendment proposal. On the basis that the status quo addresses the proposal's objective, eventually these incremental costs would need to be incurred. Therefore, the benefit would primarily relate to the time value of money saving in relation to these costs, and potentially some cost savings or efficiency benefits from future technological innovation in the gathering, storage, transfer and processing of disaggregated half-hour metered quantities.

3.44. The Authority considers the main drawback of relying on the status quo would be the time taken to realise the benefits associated with using disaggregated half-hour metered quantities in the reconciliation process.

3.45. Currently, only 45.7% of half-hour metered ICPs have their half-hourly data submitted for reconciliation. Given the rollout of smart metering began some 20 years ago, the Authority is not convinced that relying on the status quo will result in all premises with half-hour metering having their metered quantities submitted into the reconciliation process as half-hour quantities within the same timeframe as the Code amendment proposal.

3.46. Therefore, we consider the Code amendment proposal's net benefit is unlikely to be realised as quickly and to the same extent under the status quo. For this reason, the status quo is not the Authority's preferred option.

Require the submission of aggregated half-hourly quantities

3.47. The second alternative way of addressing the Code amendment proposal's objective is to require electricity traders to submit into the reconciliation process, as *aggregated* half-hourly quantities, the electricity consumption/generation of half-hour metered consumers.

3.48. Under this alternative, the Authority would amend the Code to require electricity traders to submit for reconciliation the half-hourly quantities of all their half-hour metered customers. These quantities would be aggregated as per the current reconciliation arrangements, under which traders combine their customers' electricity consumption/generation quantities[47] before submitting these aggregated quantities for reconciliation. This alternative represents an extension of the current obligation on traders to provide aggregated half-hourly quantities to the reconciliation manager for all their larger customers.[48]

3.49. As with the Code amendment proposal, this alternative would have the benefits of:

(a) allocating half-hour metered consumers' electricity use/generation to the correct trading period

(b) improving the accuracy of the allocation of electricity consumption using the balancing area residual profile shape

(c) reducing unaccounted-for-energy.

3.50. However, this alternative would not remove the siloing of metering information by reconciliation participants, which is one of the benefits of the Code amendment proposal. Also, this alternative would not provide an opportunity to begin simplifying reconciliation-related processes undertaken by the electricity industry and reducing operating costs for the industry. As discussed under the proposal's benefits, if the reconciliation manager was to aggregate all metered electricity quantities for the purposes of wholesale reconciliation, this would be expected to lower traders' operating costs and possibly provide a lower cost means of giving effect to future changes in New Zealand's electricity distribution networks.[49]

3.51. The Authority expects the implementation costs of this alternative would be less than the Code amendment proposal, with the main cost impact being the handling of more data by traders and the reconciliation manager. We expect changes to traders' systems and processes would be required to efficiently aggregate significant amounts of half-hour metering data, since traders would need to provide the reconciliation manager with aggregated half-hour metered quantities for every half hour during a month. So, a trader that currently submits two aggregated quantities for a group of half-hour metered customers would need to submit approximately 2,880 aggregated quantities for that same group of customers.[50]

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47 Consumption volumes are aggregated separately from generation volumes.

48 Being consumers with a category 3, category 4, or category 5 metering installation. See clause 2(1)(a) of Schedule 15.3 of the Code.

49 See paragraphs 3.14 to 3.15.

50 An average of approximately 30 days per month multiplied by 48 trading periods per day, for customers' consumption and generation during a month.

3.52. In contrast, we expect that implementing this alternative should require minimal changes to the reconciliation manager's systems and processes. The increase in data transferred from traders to the reconciliation manager would be an order-of-magnitude less than under the Code amendment proposal, as would the amount of data processed and stored by the reconciliation manager.

3.53. The Authority expects the cost of data exchange under this alternative would be materially less than under the Code amendment proposal — due to the much smaller change in data volumes and the less frequent data exchanges needed.

3.54. On balance, the Authority prefers the Code amendment proposal to the second alternative. This is because we believe the additional identified benefits associated with submitting disaggregated half-hour metered quantities into the reconciliation process would outweigh any associated upfront costs. As discussed, an upfront investment in the submission of disaggregated half-hourly quantities would provide an opportunity to reduce operating costs for the electricity industry both in the short term and beyond.

The proposed amendment is preferred to the alternatives

3.55. Having evaluated the two alternative means of achieving the Code amendment proposal's objective, the Authority prefers the proposal. This is for the reasons set out in our evaluation above.

Q6. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option by reference to the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

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

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

3.57. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to the direct dealings between participants and these consumers.

3.58. The Authority considers the Code amendment proposal is necessary or desirable to promote the efficient operation of the electricity industry. The proposal would do this primarily by incentivising traders to offer and promote products and services that encourage demand-side flexibility. Over the coming years demand-side flexibility is expected to have a significant benefit as New Zealand's economy electrifies, by partially offsetting new electricity generation and network infrastructure. The proposal would also enable reductions in the electricity industry's operating costs. By promoting the efficient operation of the electricity industry in these ways, the Code amendment proposal would benefit consumers by placing downward pressure on electricity prices.

Table 1: Consideration of the Code amendment proposal against the Government Policy Statement on Electricity

Principle	Consideration
3.a) An efficient wholesale electricity market with many different wholesale buyers and sellers of electricity, managing their own risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors	The proposal aligns with the Government Policy Statement as it would promote the efficient operation of the wholesale electricity market. It would do this by: • incentivising traders to offer and promote products and services that encourage demand-side flexibility, which can help offset new electricity generation and network infrastructure • enabling reductions in the electricity industry's operating costs. Consumers would benefit from this through electricity bills that should be lower than they otherwise would be.
5. Meeting increased demand for electricity over the coming 30 years will require a huge increase in investment in new generation and related services[51] — running into many tens of billions of dollars. This investment must be efficient to deliver reliable electricity supply at lowest possible cost to consumers.	The proposal aligns with the Government Policy Statement as it would promote efficient investment in new generation and related services, including the upgrading of transmission and distribution networks. It would do this by incentivising traders to offer and promote products and services that encourage demand-side flexibility which can help offset new electricity generation and network infrastructure. Consumers would benefit from this through electricity bills that should be lower than they otherwise would be.
6. Technology advances are making it easier for new players (including households) to provide generation, energy storage or demand response services. It is important that our system promotes innovation across the system for the benefit of consumers.	The proposal aligns with the Government Policy Statement by requiring half-hour metered electricity data to be submitted into the wholesale electricity market's reconciliation process in a disaggregated format. This would make better use of smart meter capabilities and encourage greater demand-side flexibility.

Q7. Do you agree the proposed amendment complies with sections 17(1) and 32(1) of the Electricity Industry Act 2010?

[51] Which includes upgrading the transmission and distribution networks.

The Authority has given regard to the Code amendment principles

3.59. When considering amendments to the Code, the Authority is required by its Consultation Charter to have regard to the following Code amendment principles, to the extent that the Authority considers them applicable. Table 2 (below) describes the Authority's regard for the Code amendment principles in the preparation of the Code amendment proposal.

Table 2: Regard for Code amendment principles

Principle	Consideration
1. Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	Section 2 of this paper sets out the case for regulation. In summary, the Authority considers that requiring the submission of half-hour metered quantities for wholesale reconciliation would help incentivise the use of demand-side flexibility. This in turn would promote efficient investment in electricity industry infrastructure needed as New Zealand's economy becomes more electrified. The Authority is also concerned that continuing use of load profiling for a substantial amount of the electricity consumption quantities submitted into the wholesale market's reconciliation process creates unnecessary inefficiencies in the process.
2. Costs and benefits are summarised.	The costs and benefits of the Code amendment proposal are set out in the evaluation of the costs and benefits in section 3 of this paper. The Authority considers key benefits of the Code amendment proposal include: • incentivising traders to offer and promote products and services that encourage demand-side flexibility which can help offset new electricity generation and network infrastructure • enabling reductions in the electricity industry's operating costs. The Authority considers key costs of the Code amendment proposal include: • traders changing their systems and processes to provide disaggregated half-hour metering quantities to the reconciliation manager for all their half-hour metered customers • the reconciliation manager changing its systems and processes to receive disaggregated half-hour metering quantities for all ICPs.

Appendix A Proposed amendments to the Code

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.

Electricity Industry Participation Code 2010

Part 11
Registry information management

…

11.26 Reports to reconciliation manager

By 1600 hours on the 3rd~~4th~~ business day of each calendar month, in respect of the immediately preceding consumption period, and by 1600 hours on the 13th business day of each calendar month in respect of the immediately preceding 14 consumption periods, the registry manager must deliver the following reports to the reconciliation manager:

(a) for ICPs with either non half-hour metering or both non half-hour metering and half-hour metering, a report identifying the number of ICP days per NSP, differentiated as applicable by ~~half-hour metering type or~~ non half-hour metering type and 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, including metering category 0 (unmetered), 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:

(b) a report detailing the loss factor values for each loss category code recorded in the registry in respect of all trading periods:

(c) a report detailing the balancing area to which each NSP belongs recorded in the registry in respect of all trading periods (including any changes during that month):

(d) a report detailing the half hour ICP identifiers and the NSPs to which they are assigned for each individual trader (including any changes during that month):

(e) a report that sets out every switch made under clauses 2, 9 or 14 of Schedule 11.3, the effect of which is that a trader has commenced trading at an NSP or a trader has ceased trading at an NSP;

(f) for ICPs with only half-hour metering, a report identifying the number of days per ICP per NSP 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.

Electricity Industry Participation Code 2010
Part 15
Reconciliation

…

~~15.6 Retailer and direct purchaser ICP days information~~

~~(1) Each retailer and direct purchaser (excluding direct consumers) must deliver a report to the reconciliation manager detailing the number of ICP days for each NSP for each submission file of submission information in respect of—~~

~~(a) submission information for the immediately preceding consumption period, by 1600 hours on the 4th business day of each reconciliation period; and~~

~~(b) revised submission information provided in accordance with clause 15.4(2), by 1600 hours on the 13th business day of each reconciliation period.~~

~~(2) The retailer or direct purchaser must calculate the ICP days information in subclause (1) using the data contained in the retailer's or direct purchaser's reconciliation system when it aggregates volume information for ICPs into submission information.~~

...

15.19 Seasonal adjustment and profiling

(1) The reconciliation manager must process submission information derived from non half hour volume information using a profile to allocate the non half hour submission information to trading periods in accordance with Schedule 15.4.

(2) Profiles must be established and changed (if necessary) in accordance with Schedule 15.5.

(3) For each reconciliation revision, the reconciliation manager must—

(a) subject to paragraph (c), recalculate the seasonal adjustment shape for each reconciliation revision cycle; and

(b) reconcile submission information using the latest profile shape published, and the most recently supplied profile information; and

(c) recalculate the residual profile shape and any shapes approved as NSP derived profile shapes under clauses 19 to 24 of Schedule 15.5 for each reconciliation revision cycle and use the shape to allocate non half hour data across the trading periods, in accordance with Schedule 15.5; and

(d) not recalculate the seasonal adjustment shape after the month ~~7~~5 reconciliation revision.

(4) Subclause (3)(d) does not prevent the reconciliation manager from recalculating the seasonal adjustment shape following the month ~~7~~5 reconciliation revision if necessary to resolve a dispute under clauses 14.25 or 15.29, or to correct information under clauses 15.21 to 15.26.

...

15.25 Reconciliation manager must assess information not supplied

(1) If a reconciliation participant fails to provide any information to the reconciliation manager that the reconciliation participant is required to provide under this Part, the reconciliation manager must take all reasonable steps necessary to acquire or estimate the information, and in the case of missing trader data the reconciliation manager must—

(a) estimate a purchaser's volume information by applying ~~the~~ ICP ~~day~~ days scaling ~~factor~~ in accordance with Schedule 15.4; and

(b) estimate a generator's volume information by using an estimated reading.

(2) Subclause (1) does not apply to information that the reconciliation manager is directed by the Authority to correct under clause 15.26(2).

...

15.27 Reconciliation manager must reconcile revised information

(1) If the reconciliation manager receives revised NSP information or submission information that has been supplied to it since the previous reconciliation calculation in accordance with clauses 15.4(2) or 15.12, the reconciliation manager must reconcile the information in accordance with the following procedure:

(a) if the submission information received relates to 1 or more consumption periods being 1, ~~3,~~ ~~7~~5, or ~~14~~13 months before the current reconciliation period, a further reconciliation must be conducted for that consumption period or those consumption periods:

(b) if the NSP information or submission information relates to any other consumption period, the reconciliation manager must store the information and wait until the consumption period becomes 1 of the consumption periods described in paragraph (a) before conducting a further reconciliation.

(2) The reconciliation manager must not reconcile revised NSP or submission information arising after month ~~14~~13.

(3) Subclause (2) does not prevent the correction of information under clauses 14.28, 15.26(2) or 15.29.

15.28 Transitional provisions concerning revisions

(1) In this clause ~~—~~

~~(a)~~ "transitional revisions" means any revision carried out by the reconciliation manager in accordance with this clause, for any reconciliation period that includes a trading period that occurred before [date Code amendment comes into effect] ~~1 May 2008; and~~

~~(b) "incumbent retailer" means, for each balancing area, the relevant retailer to be set out in the list of NSPs by balancing area and their corresponding retailers, published from time to time by the reconciliation manager, in accordance with subclause (3).~~

(2) The intent of this clause is—

(a) as far as practicable, to preserve the effect of the reconciliation provisions concerning revisions that were in effect immediately before [date Code amendment comes into effect] ~~1 May 2008~~, for all transitional revisions; and

(b) to clarify that volume information and submission information for all transitional revisions (except as provided in this clause) must be submitted by reconciliation participants in accordance with this Part; and

(c) to clarify the application of certain clauses concerning disputes that existed before [date Code amendment comes into effect] ~~1 May 2008~~.

~~(3) The reconciliation manager must publish a list of the incumbent retailers finalised under rule 11.4.3.2 of part J of the rules until all transitional revisions are completed.~~

(4) Despite anything in this Code—

(a) to avoid doubt, clause 8 of Schedule 15.3 applies to submission information in relation to all transitional revisions; and

(b) each reconciliation participant~~, including each incumbent retailer,~~ must submit the required submission information relating to all transitional revisions in accordance with clause 15.4(2)~~; and~~

~~(c) if the submission information to be supplied for a transitional revision is the first such submission after 1 May 2008, the reconciliation participant must provide a full data set as if it were an initial submission in accordance with clause 15.4(1); and~~

~~(d) in recognition of the fact that incumbent retailers have not, before 1 May 2008, been required to submit the submission information referred to in paragraph (b), the certification and audit requirements of Schedule 15.1 (required for activities in accordance with clauses 2 to 8 and 11 of Schedule 15.3, and clause 17 of Schedule 15.4), do not apply in relation to the non half-hour metering information required to be submitted by incumbent retailers to the reconciliation manager for transitional revisions~~.

(5) ~~Despite anything in this Code, all~~ All transitional revisions must be carried out by the reconciliation manager in accordance with this Code~~, subject to the following:~~

~~(a) for the purposes of clause 7 of Schedule 15.4, the ICP scaling factor is 1; and~~

~~(b) for the purposes of clauses 18(1)(b) and 19 of Schedule 15.4 the scorecard rating (SCri) for each retailer (other than the incumbent retailer) is 1; and~~

~~(c) for the purposes of clause 19 of Schedule 15.4, at each NSP the market share proportion (MSRi) for the incumbent retailer is 1, and, for all other retailers, is 0~~.

(6) Despite anything in this Code, all disputes concerning metering installations or consumption information in relation to transitional revisions—

(a) that existed before [date Code amendment comes into effect] ~~1 May 2008~~ are not affected by the coming into effect of ~~part J of~~ the revisions to ~~rules and~~ this Part on [date Code amendment comes into effect]; and

(b) must be commenced no later than 2 years after the date of issue of any invoice to which the disputed information relates.

~~(7) Despite anything in this Code—~~

~~(a) as soon as practicable after 16 October 2008, the reconciliation manager must publish 1 seasonal adjustment shape for each balancing area that existed at the beginning of the 1st trading period of May 2008; and~~

~~(b) the reconciliation manager must not publish any further seasonal adjustment shapes for the consumption periods for which transitional revisions are required; and~~

~~(c) no later than 5 business days after the date on which those seasonal adjustment shapes are published, each reconciliation participant must provide submission information to the reconciliation manager based on those seasonal adjustment shapes for the months of February to July 2008; and~~

~~(d) as soon as practicable after the expiry of the time referred to in paragraph (c) the reconciliation manager must complete revisions using that submission information for the months of February 2008 to July 2008; and~~

~~(e) each reconciliation participant must continue to use the seasonal adjustment shapes published by the reconciliation manager under paragraph (a) for all subsequent transitional revisions for the period for which transitional revisions are required.~~

...

15.37A Reconciliation participants ~~-~~ to arrange for regular audits

Each reconciliation participant with one or more obligations under this Part must arrange to be audited regularly under Part 16A in respect of those obligations.

...

15.38 Functions requiring certification

(1) Subject to subclause (3), and to clauses 2A and 2B of Schedule 15.1, a reconciliation participant must obtain and maintain certification under Schedule 15.1 to be permitted to perform, or to have performed by an agent or agents, any of the following functions under this Code:

(a) maintaining registry information and performing ICP switching (except if the maintenance of registry information is carried out by a distributor under Part 11):

(b) gathering and storing raw meter data:

(c) creating and managing (including validating, estimating, storing, correcting and archiving)—

(i) half hour volume information; or

(ii) non half hour volume information; or

(iii) half hour and non half hour volume information:

(iv) *[Revoked]*

(d) delivery of:

~~(i) a report under clause 15.6 and the calculation of the number of ICP days detailed in the report:~~

(ii) electricity supplied information under clause 15.7:

(iii) information from retailer and direct purchaser half hourly metered ICPs under clause 15.8:

…

Schedule 15.2 cl 15.5

Collection of volume information

...

4 Permanence for the purposes of reconciliation

(1) Only volume information created using validated meter readings, or if such values are unavailable, permanent estimates, has permanence within the reconciliation processes (unless subsequently found to be in error).

(2) The relevant reconciliation participant must, at the earliest opportunity, and no later than the month ~~14~~13 revision cycle, replace volume information created using estimated readings with volume information created using validated meter readings.

(3) If, despite having used reasonable endeavours for at least 12 months, a reconciliation participant has been unable to obtain a validated meter reading, the reconciliation participant must replace volume information created using an estimated reading with volume information created using a permanent estimate in place of a validated meter reading.

...

8 Non half hour meter reading on 12 monthly basis

(1) Each reconciliation participant must ensure that, at least once every 12 months, a validated meter reading is obtained for every meter register for non half hour metered ICPs at which the reconciliation participant trades continuously for each 12 month period. ~~In carrying out this obligation—~~

~~(a) each reconciliation participant must report to the Authority, in relation to each NSP, the percentage of the ICPs from which consumption information was collected and reported into the reconciliation process in the previous 12 month period. This report must be submitted no later than 20 business days after the end of each month; and~~

~~(b) if the percentage reported in accordance with paragraph (a) is less than 100%, the Authority may, from time to time, require the reconciliation participant to explain why that level was not achieved and to describe the steps that are being taken to achieve a level of performance that, in the Authority's assessment, is reasonable.~~

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

9 Non half hour meter reading every 4 months

(1) Each reconciliation participant must ensure, in relation to each NSP, that a validated meter reading is obtained, at least once every 4 months, for 90% of the non half hour metered ICPs at which the reconciliation participant trades continuously for each 4 months for which consumption information is required to be reported into the reconciliation process. ~~In carrying out this obligation—~~

~~(a) each reconciliation participant must report to the Authority the percentage, in relation to each NSP, of the ICPs from which consumption information was collected and reported into the reconciliation process in the previous 4 month period. This report must be submitted no later than 20 business days after the end of each month; and~~

~~(b) if the percentage reported in accordance with paragraph (a) is less than 90% in relation to any NSP, the Authority may, from time to time, require the reconciliation participant to explain why that level was not achieved and to describe the steps that are being taken to achieve acceptable performance.~~

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

~~(3) The reconciliation participant must report to the Authority monthly on a rolling 4 month basis the percentage of non half hour meter interrogations within that period.~~

...

Schedule 15.3 cl 15.4

Calculation and provision of submission information

...

2 Reconciliation participants to prepare information

(1) If a reconciliation participant is required to prepare submission information for an NSP for the relevant consumption period in accordance with this Code, the submission information for each ICP about which information is provided under clause 11.7(2)—

(aa) must comprise all volume information for the ICP:

(a) must comprise half hour volume information for the total metered quantity of electricity for:

(i) each category 1 metering installation or category 2 metering installation that is a half-hour metering installation; and

(ii) each category 3 or higher metering installation:

(ab) must not comprise half hour volume information for a non half-hour metering installation:

~~(ac) must comprise either half hour volume information or non half hour volume information for the total metered quantity of electricity for each metering installation that—~~

~~(i) is a category 1 metering installation or category 2 metering installation; and~~

~~(ii) is a half-hour metering installation:~~

(ad) must comprise non half hour volume information calculated under clauses 4 to 6 (as applicable) for the total metered quantity of electricity for each metering installation that—

(i) is a category 1 metering installation or category 2 metering installation; and

(ii) contains only non half-hour metering:

(ae) if a metering installation is a category 1 metering installation or category 2 metering installation, and the metering installation contains half-hour metering and non half-hour metering, ~~may~~ must comprise—

(i) a combination of—

(A) half hour volume information for the half-hour metering; and

(B) non half hour volume information calculated under clauses 4 to 6 (as applicable) for the non half-hour metering~~; or~~

~~(ii) non half hour volume information for the total metered quantity of electricity for the metering installation~~:

(b) *[Revoked]*

(c) must include unmetered load quantities for each ICP that has unmetered load associated with it, which must be derived from the quantity recorded in the registry against the relevant ICP and the number of days in the period, the distributed unmetered load database, or other sources of relevant information.

(1A) However, a reconciliation participant need not comply with subclause (1)~~(a)~~(ab), (1)(ad) and ~~to~~ (1)(ae)(i)(B) if—

(a) the reconciliation participant is using a profile approved in accordance with Schedule 15.5; and

(b) the approved profile allows the reconciliation participant to prepare submission information that does not comply with subclause (1)~~(a)~~(ab), (1)(ad) and ~~to~~ (1)(ae)(i)(B); and

(c) the reconciliation participant complies with the submission information requirements set out in the approved profile.

(2) To create non half hour submission information, a reconciliation participant must only use information that is dependent on a control device if —

~~(a)~~ the certification of the control device is recorded in the registry~~; or~~

~~(b) the metering installation in which the control device is located is an interim certified metering installation~~.

(3) To create submission information for a point of connection for which it is responsible, a reconciliation participant must use volume information from each metering installation for the point of connection.

(4) For the purposes of subclause (3), the reconciliation participant must calculate the volume information by applying to the raw meter data obtained from each metering installation—

(a) for each ICP, the compensation factor recorded in the registry for the metering installation; or

(b) for each NSP, the compensation factor recorded in the metering installation's most recent certification report.

...

8 Provision of submission information to reconciliation manager

(1) ~~For each metering installation for which it is responsible that is category 3 or higher, a~~ A reconciliation participant must for each trading period provide half hour submission information to the reconciliation manager for:

(a) each half-hour metering installation for which it is responsible that is a category 1 metering installation or category 2 metering installation; and

(b) each metering installation for which it is responsible that is category 3 or higher.

~~(2) For each half-hour metering installation for which it is responsible that is a category 1 metering installation or category 2 metering installation, a reconciliation participant must provide to the reconciliation manager—~~

~~(a) half hour submission information; or~~

~~(b) non half hour submission information; or~~

~~(c) a combination of half hour submission information and non half hour submission information if—~~

~~(i) the half-hour metering installation contains a combination of half-hour metering and non half-hour metering; and~~

~~(ii) clause 2(1)(ae) of this Schedule 15.3 applies.~~

(3) For each non half-hour metering installation for which it is responsible, a reconciliation participant must provide non half hour submission information to the reconciliation manager.

(4) However, a reconciliation participant need not comply with ~~subclause (2) and~~ subclause (3) if—

(a) the reconciliation participant is using a profile approved in accordance in Schedule 15.5; and

(b) the approved profile allows the reconciliation participant to provide half hour submission information from a non half hour metering installation; and

(c) the reconciliation participant provides submission information that complies with the requirements set out in the approved profile.

(5) For any unmetered load at an ICP for which it is responsible, regardless of the category of any metering installation at the ICP, a reconciliation participant must provide non half hour submission information to the reconciliation manager unless—

(a) the Authority has approved a profile for the unmetered load that allows the reconciliation participant to provide half hour submission information to the reconciliation manager for the unmetered load; and

(b) the reconciliation participant provides half hour submission information in accordance with the profile.

(6) The half hour submission information that a reconciliation participant submits under subclause (1)~~, subclause (2),~~ or subclause (4) must be volume information aggregated to the following levels:

(aa) ICP identifier:

~~(a) NSP code:~~

~~(b) reconciliation type:~~

~~(c) profile:~~

~~(d) loss category code:~~

(e) flow direction:

~~(f) dedicated NSP:~~

(g) trading period.

(7) The non half hour submission information that a reconciliation participant submits under ~~subclause (2),~~ subclause (3)~~,~~ and subclause (5) must be volume information aggregated to the following levels:

(a) NSP code:

(b) reconciliation type:

(c) profile:

(d) loss category code:

(e) flow direction:

(f) dedicated NSP:

(g) consumption period or day.

...

10 Reporting requirements

(1) By 1600 hours on the 13th business day of each reconciliation period, each reconciliation participant must report to the reconciliation manager the proportion of historical estimates prepared under clauses 4 or 4A, per NSP contained within its non half hour submission information.

(2) By 1200 hours on the last business day of each reconciliation period, the reconciliation manager must provide to the Authority a report of the proportion of historical estimates prepared under clause 4 or clause 4A, per NSP and per reconciliation participant, being used to create non half hour consumption information in respect of each consumption period being reconciled, and the Authority must publish the information.

(3) The proportion of submission information per retailer per NSP that is comprised of historical estimates prepared under clause 4 or clause 4A must, unless exceptional circumstances exist, be—

~~(a) at least 80% for revised data provided at the month 3 revision; and~~

(b) at least 90% for revised data provided at the month ~~7~~5 revision; and

(c) 100% for revised data provided at the month ~~14~~13 revision.

...

18 Calculation of scorecard rating

(1) The reconciliation manager must calculate, publish and apply the scorecard rating for each retailer as follows:

(a) the scorecard rating for each retailer must be calculated and published by the reconciliation manager in respect of each reconciliation period from which the reconciliation manager processes submission information, but must only be applied in respect of the ~~7~~5 and ~~14~~13 month revisions:

...

Schedule 15.4 cls 15.19, 15.20 and 15.21

Reconciliation procedures

1 Contents of this Schedule

This Schedule relates to the parts of the reconciliation process performed by the reconciliation manager during each reconciliation period and for relevant consumption periods in accordance with the revision cycle. The following steps comprise the reconciliation process. The requirements of each of these steps are detailed in the remainder of this Schedule. The steps are that the reconciliation manager must—

(a) adjust submission information by ICP days scaling; and

(b) apply loss factors to submission information for half hour metered ICPs that have been adjusted by ~~for~~ ICP days scaling; and

(c) profile non half hour submission information into trading periods; and

(d) apply loss factors to submission information for non half hour metered ICPs that have been adjusted by ~~for~~ ICP days scaling; and

(e) calculate unaccounted for electricity for each balancing area; and

(f) allocate consumed electricity and unaccounted for electricity to purchasers; and

(g) allocate generated electricity to generators; and

(h) produce reports.

...

~~5 ICP days scaling of submission information excluding embedded generation information~~

~~ICP scaling must be used to adjust each retailer's submission information (excluding embedded generator information) by a factor determined by the number of ICP days submitted for reconciliation compared to the number of ICP days recorded in the registry.~~

~~Compare: Electricity Governance Rules 2003 clause 4 schedule J4~~

6 ICP days information

~~(1) Each retailer and each direct purchaser (excluding direct consumers) must deliver to the reconciliation manager, in accordance with clause 15.6, the number of half hour and non half hour ICP days for the NSPs that are recorded in the registry as consuming electricity at any time during the~~

~~relevant consumption period, upon which the retailer's or direct purchaser's submission information is based.~~

(2) The registry manager must deliver to the reconciliation manager, in accordance with clauses 11.24 to 11.27, the number of half hour and non half hour ICP days per NSP each retailer and direct purchaser (excluding direct consumers) is responsible for during each consumption period.

7 ICP days scaling ~~factor calculation~~

~~(1) The reconciliation manager must, using the retailer and direct purchaser reported ICP days and registry reported ICP days, calculate ICP day scaling factors separately in respect of non half hour and half hour metered ICPs according to the following formula~~

~~$ICP_{SF} = ICPD_{REG} / ICPD_{RTLR}$~~

~~where~~

~~ICP_{SF} is the ICP scaling factor~~

~~$ICPD_{REG}$ is the number of ICP days for that retailer per balancing area as reported by the registry manager~~

~~$ICPD_{RTLR}$ is the number of ICP days for that retailer for that balancing area as reported by each retailer~~

~~provided that if—~~

~~(a) the ICP scaling factor is calculated to be less than 1, it must, for the purposes of this clause, be deemed to be 1; and~~

~~(b) the ICP scaling factor is calculated to be greater than 1, it must not exceed a figure nominated and published from time to time by the Authority.~~

~~(2) The ICP days scaling factor for direct consumers must be 1~~

(3) If ~~the ICP days value reported by~~ a retailer or a direct purchaser does not supply data to the reconciliation manager in respect of an active ICP which the registry manager records them as supplying ~~a balancing area is 0, or if data is not supplied, but in each case the corresponding ICP days value from the registry manager is not 0~~, the reconciliation manager must add to that retailer's or direct purchaser's submission information for that consumption period an amount (designated $SI_{ICPD-ADD}$) that is equal to—

(a) 25 kWh per ICP day, in respect of ~~non half hour~~ ICPs with no half-hour metering; ~~and~~

(b) 0.540 kWh per trading period per ICP day, in respect of ~~half hour~~ ICPs with a category 1 metering installation that is a half-hour metering installation;

(c) 2 kWh per trading period per ICP day, in respect of ICPs with a category 2 metering installation that is a half-hour metering installation:

(d) 40 kWh per trading period per ICP day, in respect of ICPs with a category 3 metering installation; and

(e) 100 kWh per trading period per ICP day, in respect of ICPs with a category 4 or higher metering installation.

~~(4) The relevant number of ICP days is the value reported by the registry manager.~~

(5) The reconciliation manager must, ~~when processing 0 ICP days information, and~~ if data is not supplied, use default values for profile, and loss category code, as determined by the Authority from time to time.

8 ICP days scaling of submission information (excluding embedded generator information)

(1) The reconciliation manager must ~~separately~~ apply ~~the ICP scaling factors and~~ any ~~additional~~ amount calculated in clause 7 to the reported half hour and non half hour submission information (excluding embedded generator information) of each retailer or direct purchaser (excluding direct consumers) so as to scale up any under submission of ~~the~~ submission information ~~in proportion to any under submission~~ by the retailer or direct purchaser.

~~(2) The ICP scaling factor and any amount calculated in accordance with clause 7 must be applied to the submission information according to the following formula~~

$$SI_{ICPD-ADJ} = (SI \times ICP_{SF}) + SI_{ICPD-ADD}$$

~~where~~

~~$SI_{ICPD-ADJ}$ is submission information adjusted for ICP days~~

~~SI is the amount of electricity reported as part of that retailer's or direct purchaser's submission information~~

~~ICP_{SF} is the ICP scaling factor determined in accordance with clause 7~~

~~$SI_{ICPD-ADD}$ is the default ICP 0 days volume defined under clause 7(3).~~

Schedule 15.5 cl 15.9

Profile Administration

8 New profiles

(1) Each new profile must be developed in accordance with this Schedule.

(2) No participant may apply to the Authority for a new profile for non half hour metered ICPs.

37 Removal of profiles

(1) If a profile fails an audit, the Authority must remove the profile from the list of approved profiles held by the Authority unless—

(a) either

(i) in the case of an audit performed by the Authority, the participant and the Authority agree corrective actions no later than 5 business days after the date the audit is completed; or

(ii) in the case of an audit performed by the Authority's appointed audit agent, the participant, the Authority, and the audit agent agree corrective actions no later than 5 business days after the date the audit is submitted to the Authority; and

(b) the Authority is satisfied that the agreed corrective actions have been performed no later than 3 months after the date the audit was completed.

(1A) Despite subclause (1), the Authority must immediately remove a profile that fails an audit if the participant advises the Authority that the participant will not agree to or perform the corrective actions.

(2) A participant who includes in a profile an ICP identifier that is not of the classification contained in the profile documentation breaches this Code. All alleged breaches must be reported to the Authority and resolved in accordance with the Act.

(3) The Authority may remove a profile—

(a) at the request of the profile owner that introduced the profile; or

(b) for such other reasons that the Authority decides.

(4) A profile owner that makes a request to the Authority under subclause (3)(a) must—

(a) make the request in writing; and

(b) request the profile's removal be effective from the start of the reconciliation period immediately following the date on which the Authority receives the request.

(5) If the Authority removes a profile, the Authority must decide on the actions to be taken with respect to the ICP identifiers to which the profile applied.

(6) A profile will be deemed to be removed if no ICPs have been assigned to it

Q8. Do you have any comments on the drafting of the proposed Code amendments?

Appendix B Format for submissions

Submitter	

Questions	Comments
Q1. Do you agree the issue identified by the Authority is worthy of attention?	
Q2. Do you agree with the objective of the Code amendment proposal? If not, why not?	
Q3. Do you agree with the Authority's 'minimum change' implementation approach?	
Q4. Do you agree the Authority has correctly identified the benefits and costs of the proposed amendment?	
Q5. Do you agree the benefits of the proposed amendment outweigh its costs?	
Q6. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option by reference to the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q7. Do you agree the proposed amendment complies with sections 17(1) and 32(1) of the Electricity Industry Act 2010?	
Q8. Do you have any comments on the drafting of the proposed Code amendments?	