Requiring distributors to pay a rebate when consumers supply electricity at peak times

Decision paper

16 July 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

New Zealand households and businesses are increasingly investing in solar panels and batteries to generate and store their own electricity. Many are also supplying the surplus energy they generate to their local network – but the return they get for this doesn't typically reflect the true value it provides to the local network.

Those who choose to shift their power use away from peak times, or invest in rooftop solar and batteries, will become important contributors to a more efficient and dynamic electricity system. We will all benefit from lower power costs over time as consumers help to reduce demand and boost supply at peak times, reducing the need for new generation and keeping the lines costs we all pay for through our power bills to a minimum.

In February 2025, the Electricity Authority Te Mana Hiko (Authority) consulted on two proposals identified by the Energy Competition Task Force (Task Force) that would give consumers who supply power to the network at peak times a fairer deal. These were:

- requiring distributors to pay a rebate when consumers supply electricity at peak times (Task Force initiative 2A);
- requiring large retailers to better reward consumers for the electricity they supply at peak times (Task Force initiative 2B and 2C).

This paper details the Authority's decisions following feedback on its proposals relating to distribution rebates/negative charges[1] (Initiative 2A). We have published a separate paper outlining our decision to introduce new rules that provide a platform for retailers to pass on these negative charges to consumers supplying power to the network (Initiative 2C).

These changes are intended to give consumers more choices while we also work on bigger, long-term improvements to the electricity market.

We have decided that distribution pricing methodologies must include negative charges for consumer-supplied electricity at peak times

Currently, most distribution price signals only apply to consumers using electricity, not to those supplying it back to the network. We are now requiring distributors to introduce 'negative charges' for electricity supplied by mass-market customers[2] at peak times. We consider that this will help achieve two important objectives:

- encouraging consumers to supply power to the network when it's needed; and
- fairly rewarding them when the power they supply benefits the network.

These changes will support New Zealanders making decisions about buying rooftop solar systems with batteries (or other forms of flexible generation). They will also encourage those with such systems to use them in ways that support our energy system.

We want to encourage people to supply surplus energy to the network when it's needed, because this benefits our electricity system and, over time, lowers the lines costs that we all pay through our power bills.

[1] This paper generally uses the terms 'negative charges' or 'negative prices' instead of 'rebate', which was used in the consultation paper. This makes it clearer that the new negative charges exist alongside regular distribution charges retailers must pay to distributors. The prices or charges discussed are 'negative' because the payment goes the other way – from distributor to retailer. Several submissions supported this change in terminology.
[2] In this paper, we use the term 'mass-market' to refer to residential and small business consumers.

While distribution pricing applies to retailers (not households and small businesses directly), these changes incentivise retailers to encourage their customers to change their behaviour, including by offering pricing plans that reflect these distribution (and other) price signals.[3]

We have amended our original proposals in response to submissions

The preferred option in our consultation paper proposed to address the missing price signal by mandating negative charges that reflect the specific value of consumer-supplied power for relieving congestion at specific locations on the network. This was intended to deliver relatively precise negative charges when consumers supply energy to the network.

However, following feedback from submitters we have decided that negative charges should not be so precise. Instead, they should reflect the broader, long-term benefits provided by consumer-generated power supplied at peak times. This change is appropriate and recognises that, given the tools available now, distribution pricing is better suited to sending broad signals than managing specific network constraints.

We still think distribution pricing signals are valuable for encouraging consumers to supply energy when it benefits the network, and therefore all consumers. Negative distribution charges can provide a stable price signal, which is easy to implement and reflects broader benefits that build over time from shifting consumers' electricity supply to peak times. Therefore, we are introducing principles that require distributors' pricing methodologies to include negative charges for power supplied by mass-market customers at peak times.

In light of feedback, we consider targeted constraint management is best achieved through contracted or controlled flexibility, which can provide distributors with a guaranteed supply of electricity that pricing signals cannot. We have therefore amended the principles so they no longer require negative charges for injection to be based on the value of deferring specific network investments. Distributors will not have to establish different pricing for each constrained asset on their network. Rather, the broad negative charges they provide must reflect the average costs of additional demand that can be avoided over the long term by consumers supplying power at peak times.

Next steps

The Authority will provide additional guidance for distributors to help them understand how they can calculate the avoidable 'long-run marginal cost' that forms the basis for these negative charges. The Code amendment will apply to pricing methodologies from 1 April 2026.

[3] Under Task Force initiatives 2B and 2C, retailers must provide some kind of time-varying plans. However, without an underlying distribution price signal, these time-varying plans will likely only reflect the wholesale market benefits of changing consumption/injection behaviour, even though there are also distribution benefits.

Contents

1. Purpose

1.1. The purpose of this paper is to inform industry and stakeholders about the Electricity Authority Te Mana Hiko's (Authority's) decision to amend the Electricity Industry Participation Code 2010 (Code) to require distributors' pricing methodologies to include negative charges for injection[4] from mass market customers at peak times, at a rate based on the average long-run marginal cost of peak demand that such injection can avoid.

1.2. This paper:

(a) summarises our decision to amend the Code, and outlines these amendments;

(b) sets out the context surrounding this Code amendment, including the wider Energy Competition Task Force programme;

(c) discusses the fundamental ideas underpinning our Code amendment and the relevant feedback from submissions to these ideas;

(d) explains the key elements of the final Code amendment, including where this diverges from the Code amendment initially proposed in the consultation paper;

(e) discusses other issues raised in feedback to the initial proposal in our consultation paper and our response to these;

(f) notes how the Code amendment is consistent with our statutory objectives;

(g) outlines next steps in the Authority's broader work programme to improve incentives for efficient investment in and operation of distributed generation and storage; and

(h) sets out the final Code amendment.

[4] We note that injection can come from distributed generation (such as solar PV systems), distributed storage (such as home batteries) or a combination of both.

2. We have decided to amend the Code to require distributors to provide negative charges for injection at peak times

2.1. The Authority has decided to amend the Code to include mandatory principles that require distributors' pricing methodologies to include negative charges for injection from mass market customers at peak times. These charges should be set at a rate based on the average long-run marginal cost that such injection can avoid, while taking into account uptake incentives, network stability and practicality of implementation.

2.2. This is slightly different from the Code amendment proposed in the decision paper, in two key ways.

2.3. Firstly, the principles no longer require negative injection pricing to be based on the value of specific network investments deferred. This means that distributors will not have to implement granular distribution pricing that varies for every constrained asset on their network, as was intended under the initial proposal.

2.4. Rather, injection pricing must be based the long-run marginal cost (LRMC) of peak demand that injecting into the network can avoid, with appropriate adjustments, resulting in broader price signals across an entire consumer group in a pricing region.

2.5. Secondly, distributors' pricing methodologies must show how distributors arrived at their injection pricing. This will include explaining:

(a) how the LRMC of peak demand was calculated.

(b) how the LRMC of peak demand was converted into negative charges for injection. This should include the form of negative charge (for example, whether it applies during specific hours of the day or in other specified circumstances), how the rate has been calculated (including any de-rating to account for the specific characteristics of injection), and important assumptions relied upon.

2.6. Distributors that do not have the capability to do this by 1 April 2026 may instead choose to base their negative charges on the differential between their existing peak and off-peak consumption pricing (with adjustments as necessary) for the first pricing year as a transitional arrangement.

2.7. The Authority considers that creating targeted incentives to reward injection that helps defer specific network constraints is more appropriately achieved through contracted flexibility.

2.8. We are already working on ways to make it easier for distributors to contract for flexibility in this way, including measures to improve distributors' visibility of their distribution networks, and have recently released a consultation paper on allowing consumers to have different retailers for consumption and injection.

2.9. We will also consider further actions to better enable contracted flexibility, for example by helping to produce a standardised template for flexibility contracts.[5] However, the scope of this Code amendment is limited to distribution pricing.

[5] See paragraph 4.25 for further examples.

2.10. Other elements of the initial proposal are largely unchanged:

(a) The Code amendment takes a principles-based approach, giving distributors flexibility as to how they implement specific aspects of the negative charges.

(b) Distributors' negative charges must have regard to "transaction costs, consumer impacts, uptake incentives and network stability". These factors have been slightly amended from the initial proposal to align more closely with the Distribution Pricing Principles (DPPs), but we expect them to apply in much the same way in practice.[6]

(c) Distributors must comply with the principles from the pricing year beginning 1 April 2026. We consider this date is more achievable than it would have been under the initial proposal, as the revised Code amendment will be much easier to implement.

(d) The principles apply to mass market customers only (noting that the Code amendment now refers to price categories with "eligibility criteria that are designed to target residential or small business consumers", rather than ICPs assigned to "standard contracts").

(e) The principles apply to injection from any type of generation or storage technology, noting that the injection must occur during times when demand is driving future network investment (i.e. during peak), so uncontrollable generation is unlikely to derive much value from these negative charges.

2.11. The final Code amendment is set out in Appendix A.

[6] Specifically, the previous principle of "practicality of implementation" has been replaced by "transaction costs" and the principle of "consumer impacts" from the DPPs has been added. The principle of "network stability" has been retained despite not being included in the DPPs.

3. We consulted on proposed Code changes and have considered submissions received

3.1. This section sets out the key context surrounding our decision to amend the Code, including the work of the Energy Competition Task Force, the key theory underlying our decision, and information about our consultation earlier in 2025.

This amendment is part of the Energy Competition Task Force programme

3.2. The Authority and the Commerce Commission Te Komihana Tauhokohoko jointly established the Energy Competition Task Force (Task Force) in the context of the fuel shortage and period of sustained high wholesale electricity prices in August 2024, to investigate ways to improve the performance of the electricity market.[7] This was in addition to a number of immediate steps the Authority, and others, took to help manage security of supply and bring prices down during this period.

3.3. Initiatives under the Task Force work programme focus on two core outcomes:

(a) enabling new generators and independent retailers to enter, and better compete, in the market (package one); and

(b) providing more options for end-users of electricity (package two).

3.4. These outcomes will encourage more and faster investment in new generation, boost competition, enable homes and businesses and industrials to better manage their own electricity use and costs, and put downward pressure on prices.

3.5. This paper relates to initiative 2A, "consider requiring distributors to pay a rebate when consumers export electricity at peak times", under the second outcome.

3.6. This initiative, in concert with the Authority's contemporaneous decision on time-varying pricing (initiatives 2B and 2C), seeks to:

(a) provide consumers that produce/store electricity (eg, from a solar and battery combination) with more options for managing their energy costs, through better signalling and rewarding the impact on distribution network costs of injection at peak times; and

(b) ultimately benefit all consumers by reducing the need for network (poles and wires) investment over time, as described below.

There is a missing distribution price signal for injection from distributed generation/storage

3.7. Many distributors' existing pricing plans have higher charges for consumption at peak times. This provides a financial incentive for consumers to shift load away from peak times.[8] Consumers for whom this incentive is sufficient will change their behaviour and/or invest in technologies that allow them to reduce or shift their consumption (e.g. smart EV chargers), reducing peak demand on the network. In

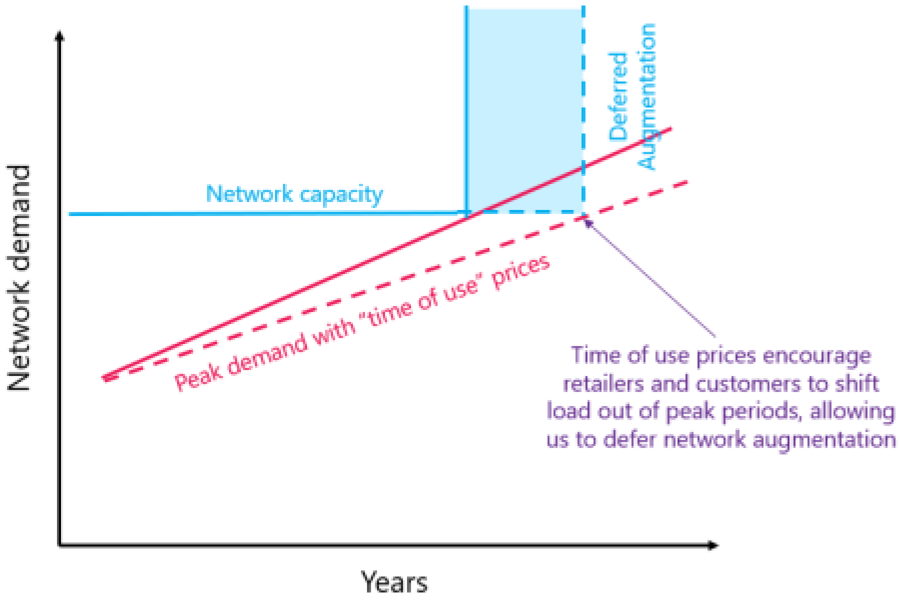
[7] With Ministry of Business, Innovation and Employment (MBIE) representatives as observers.

[8] We note that in the first instance, this incentive applies to retailers. A retailer is then incentivised to pass this signal through to consumers to minimise the retailer's distribution costs. Furthermore, under initiative 2B and initiative 2C, retailers must offer some kind of time-varying pricing to consumers, which we would expect to be influenced (at least in part) by underlying distribution price signals.

aggregate and over time, slower peak demand growth will allow future network investments to be deferred.

3.8. Powerco's [2025-2026 pricing methodology] contains a useful graphic that outlines this concept.

Figure 1: How price signals can delay distributors' upgrades of their networks



3.9. As shown in Figure 1, as peak demand (the solid pink line) grows over time, it gets closer and closer to exceeding network capacity (the solid blue line). When this occurs,[9] the distributor will need to invest in new capacity to meet growing demand.

3.10. Efficient pricing can encourage consumers to shift their demand away from peak times, resulting in slower peak demand growth (the dotted pink line). This means that it will take longer for peak demand to trigger the need to invest in new capacity.

3.11. Deferring network capacity upgrades provides cost savings for the network (in present value terms), which over the long term translate to lower distribution charges than would otherwise have been the case.

3.12. The problem definition identified in our consultation paper was that most distributors provide no such distribution price signal for injection. Consumers with distributed generation/storage can also put downwards pressure on net peak demand by injecting at times when demand is highest, benefiting the network (and ultimately the consumers who pay for it) by deferring future network investment; however, existing distribution pricing tends to provide no reward for such injection even when it provides long-term benefits.

3.13. The solution proposed in our consultation paper was to require (via codified principles) distributors' pricing methodologies to include negative charges for injection from mass market customers, when and where that injection could provide network benefits by deferring the need for specific investment.

[9] In practice, distributors will tend to make this investment before peak demand actually exceeds capacity, to ensure there is some kind of buffer.

We received submissions from a range of stakeholders

3.14. We received 138 submissions and 10 cross-submissions on our 'Requiring distributors to pay a rebate when consumers supply electricity at peak times (Task Force initiative 2A)' consultation paper.

Table 1: Number of submissions by submitter type

Category:	Submitters:
Consumers / distributed generation owners	86 written submissions 13 consumer survey responses
Distributors and associations	Alpine Energy, Aurora Energy, Counties Energy, EA Networks, Electricity Networks Aotearoa (ENA), Energy Trusts of New Zealand (ETNZ), Firstlight Network, Horizon Energy, Mainpower/Marlborough Lines, Network Tasman, Northpower, Orion, Powerco, PowerNet, The Lines Company, Unison/Centralines, Vector, Waipā Networks, WEL Networks, Wellington Electricity and Westpower.
Retailers and associations	Ecotricity, Electricity Retailers' Association of New Zealand (ERANZ), Genesis Energy, Mercury, Meridian Energy, Nova Energy, Octopus Energy, Our Energy, Paua to the People and Pulse Energy.
Other	BusinessNZ Energy Council, Climate Justice Taranaki, Common Grace Aotearoa, Community Energy Taranaki, Electricity Engineers' Association (EEA), Electrify Wanaka, FlexForum, Independent Electricity Generators Association, Lastmyle Limited, Lightforce Solar, Local Energy, Lodestone Energy, Lyttleton Energy Transition Society, Neil Walbran Consulting, Nelson Tasman Climate Forum, New Zealand Centre for Sustainable Cities, Queenstown Lakes District Council, Rewiring Aotearoa, Sustainable Energy Association New Zealand (SEANZ), Supa Energy and Utilities Disputes.
Cross-submissions	Aurora Energy, ENA, Flick Electric, Graeme Weston, Mercury, Powerco, Rewiring Aotearoa, Unison/Centralines, Vector and Wellington Electricity.

3.15. Almost all submitters agreed with the objective of the proposal that consumers should be rewarded for the network benefits their injection provides, and that there is currently a missing price signal for this. However, most also considered that the proposed solution (ie, targeted pricing) was not the best way of achieving this objective.

3.16. During the consultation period, Rewiring Aotearoa encouraged people to make submissions on our proposals. It released a consultation guide and both a simple and a more detailed submission template that included Rewiring Aotearoa's key arguments, particularly its preference for symmetrical export tariffs. We received:

(a) 49 submissions that used Rewiring Aotearoa's simple four bullet-point template.

(b) 29 submissions that largely followed Rewiring Aotearoa's more detailed template. Many submitters added useful context about their own electrification journeys and the impact they would expect Rewiring Aotearoa's proposed solution to have on their investment decisions and the decisions of others wanting to electrify.

3.17. We set out the key points raised by submitters in the following sections, along with our response to them and how these considerations are reflected in our final decision.

4. Submissions highlighted the importance of recognising the strengths and weaknesses of distribution pricing

4.1. This section sets out some overarching themes raised in submissions, particularly in relation to the relative merits of distribution pricing as a tool to improve the efficiency of distribution network investment, particularly compared to other tools such as contracted flexibility.

4.2. Our view is that distribution pricing is better suited to providing broader, more stable price signals, which led us to revise our initial proposal of requiring very targeted injection pricing.

Price-based flexibility and contracted flexibility serve different purposes

4.3. Some submitters highlighted the difference between distribution pricing and contracted flexibility.[10] For example, Orion noted that our initial proposal:

> *"appears to conflate two separate objectives:*
>
> *a) targeted deferral of specific network investments through non-network solutions (which typically requires location-specific flexibility services), and*
>
> *b) establishing broader price signals to incentivise export (which is best achieved through pricing)."*

4.4. ERANZ submitted that this caused a tension in our initial proposal "between needing rebates to accurately reflect the value posed to the distribution network, and needing a certain level of stability of rebates to incentivise consumers to install distributed generation."

4.5. Counties Energy's cross-submission referred to a paper by the British electricity regulator Ofgem that discussed the relative merits of price-based and contracted flexibility across a range of criteria. It noted that "no mechanism in isolation performs best across all criteria, while different criteria are relatively more important for different use cases."

4.6. We agree with these submissions that there is a fundamental distinction between the role of price-based flexibility and contracted flexibility, and that it is critical that our intervention matches the right tool to the right job. This distinction frames our further discussion below.

Distribution pricing is not well suited to targeted constraint management

4.7. Deferring specific network upgrades requires distributors to target incentives to consumers in the specific part of the network with the relevant constraint. The flexibility response from these consumers must also be sufficiently reliable to give distributors the confidence to defer the upcoming investment. However, we consider that implementing such targeted distribution pricing is difficult, and pricing does not guarantee that consumers with flexibility resources will respond.

[10] For example, Aurora Energy, FlexForum, Orion, Octopus Energy, Powerco.

Highly granular injection pricing would be unworkable at this stage

4.8. Our original proposal would require pricing to reward groups of ICPs for injection that benefits the network "where it avoids, reduces, or defers the costs of required investment in the network". In practice, we expect this would have required highly granular injection pricing that varied for every constrained asset on the network. [11]

4.9. Some submissions argued that our initial proposal, with its granular injection pricing, would not have been workable or effective. For example:

(a) Nova Energy considered that there was "a level of precision expected that will never be able to be met".[12]

(b) ETNZ noted that there would be costs to managing the increased number of tariffs that result from more granular pricing.[13]

(c) Waipā Networks noted that it would be "difficult to identify if an ICP or group of ICPs would be able to provide network benefits through injection".

(d) The Lines Company submitted that this would increase the number of distribution pricing categories, when the Authority has been recommending distributors "simplify the number of tariff codes across the network".

(e) Orion noted that "even as distributors develop the capability to design granular, location-specific rebate structures, some retailers lack the ability to effectively implement and pass through these complex signals to end consumers".[14]

(f) ENA noted that "there are examples of EDBs trialling more innovative pricing in specific constrained areas, where consumers in nearby unconstrained areas expressed concerns about why they couldn't access the same pricing."

4.10. On the other hand, contracted flexibility exists outside of a distributor's pricing framework. The bespoke nature of contracts means they can be tailored without creating undue complexity or billing system upgrades.[15] They can:

(a) be offered to consumers on specific parts of the network without creating new price categories;

(b) specify the precise times or circumstances when the injection is required; and

(c) be updated as required rather than being tied to a yearly pricing cycle.

4.11. We agree that highly granular pricing would be difficult to implement, particularly in the short term, and that contracted flexibility is a more workable solution for managing targeted constraints.

[11] Although we note that some submitters did not consider this was the original intent. For example, ENA noted that "to comply with the proposed 2a amendments, some EDBs may apply across all peak consumption periods, or all winter peaks, for simplicity" and Powerco noted that its plan to implement a network wide negative charge for injection would be "consistent with the Authority's proposals".
[12] Horizon Energy made a similar point.
[13] Counties Energy, Nova Energy, Orion and Powerco (particularly in its cross-submission) made similar points about more granular pricing increasing costs for distributors.
[14] Similarly, Unison/Centralines submitted that "the time, effort and cost linked to elaborate locational pricing and costly billing system upgrades would be wasted should these signals not be passed through to the end consumer." Other submitters (e.g. ENA, Mainpower/Marlborough Lines, and SEANZ) also expressed concern about lack of retail pass through, although not necessarily in the context of highly granular pricing.
[15] For example, Alpine Energy noted that "aggregators can schedule exports in response to network constraints, enabling targeted flexibility services that help to defer or avoid or costly investment in network upgrades".

Perfectly cost-reflective pricing would also be volatile

4.12. It is also difficult to target pricing to the precise times that injection can help defer specific investments. In theory, this only occurs when injection can help relieve demand-driven congestion, which is dependent on not only peak demand but also how the network is configured.[16] As FlexForum noted, “few distributors have capability to create and send temporal/locational cash signals”.

4.13. Even where such dynamic pricing could be implemented, the signal this provides would be volatile and unreliable. As discussed below (paragraph 4.33), consumers generally need stable price signals to invest in expensive flexibility resources such as batteries.

4.14. We consider that distribution pricing is better suited to providing stable signals, rather than the more dynamic ones needed for targeted constraint management. Our initial proposal therefore allowed distributors to “spread such a rebate over more frequent events or over a longer time period, to make the price signal more attractive from an investment perspective”.[17]

4.15. Some submitters disagreed with this approach – for example Waipā Networks questioned “why distributors would want to encourage long term customer investment for short term network benefit”. However, as discussed further below, the final Code amendment focuses on broader price signals that reflect longer-term network benefits of injection during peak times, rather than targeted price signals that reflect short-term benefits.

Price-based signals do not give distributors sufficient confidence to defer specific investments

4.16. As noted by Wellington Electricity, distributors have “regulatory accountability for network quality under the Commerce Act, Electricity (Safety) Regulations and Consumer Guarantees Act, with significant penalties for breaches.” Accordingly, distributors are understandably reluctant to defer a capacity investment for an imminent constraint without some level of assurance that the constraint can be sufficiently managed by flexibility (either from injection, demand response, or both).

4.17. Many distributors submitted that price signals for injection do not guarantee that consumers with distributed generation/storage will respond when needed, and that only contracted flexibility provides a sufficiently certain response for them to be confident enough to defer a specific network upgrade.[18]

4.18. We agree that pricing may not provide the certainty required to defer specific network investments in the short-term.

[16] For example, EA Networks noted that its engineers “reconfigure the network over time to address congestion, changing open points and moving load both in and out of a congested area to better utilise capacity, sometimes on a seasonal basis. This makes any pricing response volatile, as customers can find themselves within a congested area one day, and outside the congested area the next.”
[17] Consultation paper, paragraph 5.7(e).
[18] Alpine Energy, Counties Energy, EA Networks, EEA, FlexForum, Mainpower/Marlborough Lines, Northpower, Unison/Centralines, and Wellington Electricity.

We have therefore removed the requirement for injection pricing to reflect the specific benefits of deferring a particular investment

4.19. As discussed above, we now consider that distribution pricing is not well suited to targeted constraint management. In its submission, Orion recommended the Authority "remove prescriptive, location-specific requirements that may create unintended consequences". We agree, and are therefore removing any requirement for negative injection pricing to reflect the value of deferring specific investments.

4.20. The principles in our Code amendment still require negative charges for injection at peak times, but these must instead be based on the broader benefits of injection at peak times that accrue for the network, and ultimately for consumers, on average over the long term. This is discussed in more detail from paragraph 5.2.

4.21. By removing this 'targeting' requirement, distributors can apply negative charges for injection at the same level of granularity they already use for consumption pricing. Currently, most distributors have uniform prices (for each customer group) across their whole network. Some distributors divide their network into several pricing regions (for example, Unison has its Hawkes Bay region and its Rotorua/Taupō region), but these regions tend to be large. This leads to broad price signals that aim to reflect the average cost of peak demand across the whole network or region.

4.22. This is not to say that distribution pricing (for both injection and consumption) should not become more granular over time. Distributors may find it useful to divide their existing pricing regions into smaller regions if there are material differences between the costs and cost drivers between regions. However, we consider that fully granular pricing (i.e. down to the individual asset level) is unlikely to be workable or desirable, at least in the short term.

We consider contracted flexibility is a better tool for targeted constraint management

4.23. Distribution pricing is just one tool available to incentivise efficient investment in, and operation of, distributed generation/storage to minimise network costs.

4.24. As noted, another available tool is contracted flexibility, which distributors can use as a non-network solution to manage specific network constraints in the short term. This involves contracting with the owners of flexibility resources (usually via an aggregator) for control over these resources, so that the distributor can call on them when required.

4.25. Distribution pricing and contracted flexibility should work together – as Powerco's cross-submission noted, "we see [contracted flexibility] as complementary to the regional long-run marginal cost signal which is available universally." However, use of contracted flexibility to defer network investment in New Zealand has been limited to date.

4.26. Some distributors noted that this is at least in part due to a lack of flexibility resources currently in the market.[19] We expect that this Code amendment (i.e. broad negative charges for injection at peak) will provide a stable investment signal for consumers to invest in batteries and other flexibility resources which, as discussed in the following section, should increase the number of flexibility resources available for distributors and/or aggregators to contract with.

[19] ETNZ, Northpower, Orion, Wellington Electricity.

4.27. The Authority will consider other potential ways to help make contracted flexibility more accessible to distributors. While we are still considering how this could be taken forward in our broader distribution network regulation workstreams, we note that some submitters made the following suggestions:

(a) Improving distributors' visibility of their low voltage networks,[20] so that they can better identify specific constraints, as well as the customers that could help manage these constraints through flexible generation/storage and demand response. The Authority is already working on this. This could also include requiring distributors to publish information on identified constraints, including the terms/prices they would accept for flexibility solutions to manage these constraints.

(b) Enabling multiple trading relationships (MTRs)[21] so that consumers can have a separate 'retailer' for their injection (i.e. an aggregator that manages their injection and can provide contracted flexibility to the distributor). The Authority has recently released a consultation paper on this topic.

(c) Helping produce a standardised template for flexibility contracts.

(d) Establishing a national register of flexibility providers.

4.28. We will consider further additional reform that could help distributors procure more contracted flexibility in future, including the options outlined in the paragraph above.

Negative distribution prices can still provide useful long-term signals

4.29. While not well suited to targeted constraint management, we consider that broader price signals can still be a useful tool for incentivising efficient investment in and operation of distributed generation/storage.

4.30. Broad price signals provide an incentive to generally shift injection towards peak demand periods. In aggregate (ie, after diversity of supply is taken into account),[22] this reduces net peak demand on the network, reducing or deferring the investment required across the whole network over the long run. This can provide generalised, long-term benefits (rather than targeted, short-term benefits).

4.31. Compared to contracted flexibility or highly granular pricing, we consider broad negative pricing for injection has two key advantages. As noted by Ecotricity's submission:

> *"1. It simplifies pricing approaches for EDB's i.e. they set one rebate rate across their network; and*
>
> *2. It means that [distributed generation] (and associated flexibility) will be built before there are critical network issues"*

[20] For example, ENA, Northpower, PowerNet, SEANZ.

[21] For example, BusinessNZ Energy Council, ENA, Paua to the People, SEANZ.

[22] Rewiring Aotearoa noted in its cross-submission that distributors "can receive significant benefits and reliability in aggregate from battery installations without needing to have 100% perfect control of them 100% of the time".

Broad price signals are simpler and easier to implement

4.32. Distribution pricing must balance accuracy and simplicity. As Aurora Energy noted:

> *"It is crucial to strike a balance between accuracy and simplicity to ensure that export tariffs provide effective incentives without adding unnecessary complexity."*[23]

4.33. Broad price signals can be implemented relatively easily. They are easy for distributors to establish, retailers to pass through, and consumers to understand.[24] They don't require granular network information or establishing a potentially unmanageable number of different pricing groups. This was noted by ENA's submission, which stated that:

> *"A more 'high-level' and less targeted approach, such as applying rebates to all exports at winter peak, regardless of whether a network benefit can be demonstrated in all cases, may be more achievable."*[25]

4.34. Similarly, Powerco's cross-submission argued that:

> *"Clarifying that export rebates are simply intended to be negative prices in posted distribution tariffs credited to retailers and calculated across the same regions as demand prices would address the majority of submitters' concerns about the cost, complexity and efficiency of implementing rebates."*

Stable signals encourage initial uptake of flexibility resources

4.35. Several submitters noted that pricing needs to be relatively stable.[26] Batteries and other flexibility resources tend to be expensive, with long pay-back times, so to the extent that consumers' investment decisions rely on the price signal from these negative charges, they need to be confident that the signal will be enduring.

4.36. Broad price signals are relatively stable. Under the revised principles, they will be based on the average LRMC of peak demand avoided by injection across the whole consumer group/pricing region. While individual investments in network capacity or small pockets of demand growth may affect the true value of injection at a specific part of the network at a specific time, the average LRMC upon which the price signal is based is unlikely to change significantly in a short period of time.

4.37. This means that consumers are generally incentivised to invest in flexibility resources, so that when a specific constraint arises on their part of the network resources are ready and available to provide a flexibility response (and are likely to already be doing so to some extent).[27] This can avoid the "chicken or egg" scenario faced by contracted flexibility, where there are low levels of flexible distributed

[23] Counties Energy, ENA, and Powerco made similar points.

[24] Rewiring Aotearoa noted that their proposed symmetrical export tariff solution (which differs from our final Code amendment, but still involves broad price signals) would be "simple for consumers and networks to understand" and "simple for networks to implement". Many consumer submissions made the same point.

[25] Other submitters made similar points. For example, Unison/Centralines noted that they did not support generic negative charges, but these could be implemented more quickly than "more strategic and locational prices". The Ofgem paper referenced in Counties Energy's cross-submission, also noted that "some charge designs (such as a seasonal time-of-use charges) are likely to be relatively simple to implement."

[26] For example, Meridian Energy noted that "for most consumers the purchase of a battery would have to be based on multi-year returns. Therefore, without stable returns evaluating the value of purchasing a battery in order to receive the rebate would be difficult, meaning the incentives to invest are limited". EA Networks, ENA, Genesis Energy, Paua to the People, and Vector made similar points.

[27] As noted by Ecotricity, "if DG and associated flexibility is valued at all points of a network before it is urgently needed, then a mature flexibility market can develop, with assets available ahead of the electrification curve."

generation/storage due to a lack of incentives, but distributors do not offer incentives because there are few customers who can respond (as already noted). Therefore, price-based flexibility is particularly useful "where flexibility markets are in their infancy".[28]

Broad price signals are used in consumption pricing already

4.38. The issue of the missing distribution price signal for injection was highlighted in a 2024 Rewiring Aotearoa report on the case for symmetrical export tariffs. Many submissions, including from consumers, noted that consumption pricing already applies in a fairly untargeted way across the network, and if this degree of granularity is acceptable for consumption pricing, it should be acceptable for injection pricing also.[29]

4.39. While we disagree that fully symmetrical export tariffs should be required (see our discussion from paragraph 6.2), we agree with the underlying logic that neither consumption nor injection pricing needs to be perfectly cost-reflective, and that a degree of simplification is likely to be more efficient than no price signal at all.

Some submitters argued that broad price signals are not suitable for injection

4.40. On the other hand, some submitters argued that, while broad price signals for consumption pricing are useful in balancing accuracy and simplicity, a different approach is needed for injection pricing.

4.41. In particular, some submitters noted that injection may be more responsive to price than consumption, so untargeted pricing could lead to 'herding' or 'battery dumping', where stored energy is released all at once as soon as negative charges apply, leading to potential export congestion and voltage issues.

4.42. For example, Waipā Networks noted that:

> *"Peak charges are broadly applied and broadly cost-reflective rather than applied to specific areas of the network experiencing congestion. […] Applying this broad approach to injection tariffs though would run the risk of herding and cause export congestion issues and increase network costs."* [30]

4.43. We agree that injection has specific characteristics, particularly its price-responsiveness, that mean there is an extent to which it may be efficient to set injection pricing at a level that is more accurate and less simplified than consumption pricing.[31]

4.44. Importantly though, we disagree with the argument that these differences mean injection pricing can only be beneficial if it is perfectly cost-reflective (which by implication, would require it to be extremely granular, dynamic and complex).

[28] See Ofgem paper referenced in Counties Energy's cross-submission.
[29] For example, Queenstown Lakes District Council considered it "unclear why the spatial inaccuracy and inefficiency of a tariff is a concern for a minority group of battery owners but is not a concern for all electricity consumers." Aurora Energy noted that "just as consumption tariffs act as broad signals rather than exact cost reflections, export pricing should be practical, transparent, and aligned with long-term network efficiency goals." Powerco noted "distribution export pricing should be consistent with demand pricing and that distribution pricing reform is a work in progress and "unlikely to be perfectly cost-reflective"."
[30] Aurora Energy and ENA expressed similar concerns about 'battery dumping'.
[31] We discuss this point in more detail in relation to symmetrical export tariffs from paragraph 6.2.

Rather, we consider a simplified broad price signal strikes an appropriate balance, even if more targeted (or a weaker signal) than its consumption pricing equivalent.

4.45. The risks of incentivising too much injection at a particular time (eg, 'herding' or 'battery dumping') could be mitigated in a number of ways. For example:

(a) The negative charge could apply to more targeted peak periods (eg, fewer hours in a day, or only in seasons when peak demand is highest). This should reduce the likelihood of incentivising injection at times where it may exceed demand and drive additional costs.

(b) The negative injection charge could be 'de-rated' relative to the equivalent cost-reflective consumption charge. This would reflect that injection can in some circumstances drive additional costs (particularly if herding occurs), and injection pricing should be based on the *average net* benefits/costs created by that injection from that pricing group during the specified period.

(c) Distributors could use network standards to restrict excessive levels of injection. These could be as simple as fixed export capacity limits, or more complex mechanisms such as dynamic operating envelopes.

Other submitters considered that the benefits of broad price signals are low

4.46. A number of submitters considered that the benefits of broad price signals were too low to justify intervention. For example:

(a) Several submitters noted that the financial impact of broad negative charges for injection on consumers with batteries (under our 'consumption linked injection tariff' approach) as modelled in Appendix A of our consultation paper were very low.[32]

(b) Unison/Centralines considered that "a broad export rebate is an inefficient signal that provides incentive where there is no benefit and can encourage over-investment which, as is the case in other jurisdictions, can lead to network issues, resulting in additional costs".[33]

(c) EA Networks considered that pricing solutions "carry a high transaction cost, are not targeted enough and will lead to rewards being applied where there is no corresponding network benefit."

4.47. As noted above in paragraph 4.28, we consider that there are benefits resulting from broad price signals which are more generalised and accrue over the longer term.[34] While the proposal is unlikely to avoid specific capex in the short to medium term, we agree with FlexForum that "in the longer term the new normal discretionary responses will be predictable and baked into asset planning", and provide more generalised benefits in this way, first to the network and ultimately to the consumers that pay for the network.

4.48. We also note that while modelled financial impact was low for average-sized batteries used almost entirely to offset consumption, larger batteries or different

[32] For example, ENA, ERANZ, Meridian Energy, PowerNet.
[33] EA Networks made a similar point, noting that "pricing incentives are a blunt tool. While they may drive cost savings in some situations, in other situations they will increase costs. It is not clear to us that the uncertain benefits outweigh the certain costs (in addition to the transaction costs)".
[34] As noted by John Hilhorst's submission, "price-based flexibility through rebates provides broad signals to the market that can incentivize DG investment and operation in beneficial ways".

operating modes that increased the amount of *injection* into the network could result in more material payments. We discuss this in more detail from paragraph 6.17.

4.49. Other submitters considered that the high implementation costs of our initial targeted proposal would outweigh the benefits.[35] However, we note that:

(a) Our revised Code amendment only requires broad injection pricing, which will have lower implementation costs.[36]

(b) Multiple submitters considered the short-term implementation costs of our initial proposal were still likely be outweighed by benefits over the long term.[37]

(c) Even among submitters that believed that the implementation costs of the initial targeted proposal would outweigh the benefits, some still agreed that the logic behind negative injection pricing was sound.[38]

Negative charges for peak injection are already being implemented in New Zealand and Australia

4.50. The idea that distributors should pay for injection that occurs at peak times through broad negative distribution charges is not novel.

4.51. This kind of pricing is becoming more widespread in Australia, where it is known as a "two-way tariff". A key feature of two-way tariffs is that, in addition to negative charges for injecting when demand is highest (eg, during the evening peak), they also have regular charges for injection that occurs when supply is highest (eg, during the middle of the day, when solar generation is strongest).[39] This is important because Australia has a large amount of rooftop solar, much of which does not include batteries, which has led to export congestion on many distribution networks.

4.52. Analysis from Ausgrid, one of the Australian distributors, found that customers on its two-way tariff trial tended to export later in the day than typical customers, indicating that broad price signals can change the average consumer's injection profile, and therefore the average net demand profile on the network.

4.53. Several New Zealand distributors are also already implementing negative pricing for injection during peaks. Aurora Energy is continuing a trial where medium-sized connections can count "50% of their kWh exported during control periods against their annual CPD calculation". Orion and Powerco have introduced negative pricing for the 2025-26 pricing year. While we are pleased to see progress occurring voluntarily, this Code amendment will ensure that all distributors improve their pricing methodologies in relation to injection.

[35] For example, Nova Energy considered that "the complexity of trying to calculate with precision the right level of pricing signal will create transaction costs in development of them, as well as ongoing administration that are higher than the expected benefits".
[36] As discussed at paragraphs 4.31 and 4.32.
[37] For example, Octopus Energy noted that "the implementation costs for distributors and retailers will be modest compared to the long-term system benefits of more efficient network investment, reduced peak demand, and greater customer engagement in demand-side management." Counties Energy, Graeme Weston, Neil Walbran Consulting also agreed that the benefits of the initial proposal outweighed the costs.
[38] For example, Waipā Networks considered that the "principles themselves are sound and in the interests of fairness we believe a rebate in some form is justified." The Lines Company made a similar point.
[39] Counties Energy advocated that a similar charge should apply in New Zealand.

5. We have revised some elements of our approach in response to points raised by submitters

5.1. This section sets out the key elements of our final decision to amend the Code. In particular, it highlights where elements have changed from our initial proposal.

Negative charges must be based on the LRMC of peak demand that can be avoided by injection

What we proposed

5.2. Our initial proposal required distributors to identify specific ICPs or groups of ICPs that could provide network benefits by deferring specific investments, and to provide negative charges based on these specific benefits.

What submitters said

5.3. As discussed above, submitters identified a fundamental distinction between the benefits of deferring a specific investment using “targeted constraint management” (which are better achieved through contracted flexibility rather than the initial proposal), and the more general long-term benefits from “broad price signals”.

Our response

5.4. Having taken submissions into account, we consider that negative charges for injection should be based on broader, averaged long-term benefits – ie, the avoided LRMC of peak demand.[40] The Code amendment now requires distributors’ negative charges to be based on “the long-run marginal cost of peak demand that can, on average and over time, be avoided by injection that occurs at the times identified in paragraph (a) above from ICPs in that price category”.[41] Distributors should already calculate this LRMC figure for the purpose of setting their peak consumption charges.

5.5. The Authority will provide guidance on how the LRMC should be calculated, as well as considerations when converting this into a negative charge for injection. For the avoidance of doubt, we also consider that the Code amendment is generally consistent with the 2019 Distribution Pricing Principles (DPPs), and that the guidance in the practice note is also applicable to injection pricing.[42] Additional high-level guidance points are set out below.

[40] This approach was suggested in several submissions. Orion recommended the Authority “remove prescriptive, location-specific requirements that may create unintended consequences”. Aurora Energy recommended that “export tariffs should align with LRMC assumptions”. Powerco recommended “clarifying that export rebates are simply intended to be negative prices in posted distribution tariffs credited to retailers and calculated across the same regions as demand prices”, noting that its own injection pricing is “based on the same long-run marginal cost of network augmentation planned in our AMP by pricing region”.

[41] Paragraph (a) refers to “times when demand in the region where the ICPs in that price category are located is likely to, on average and over time, drive future network investment”.

[42] We note that the section of the DPPs on “PV installation with storage/other DER” recommends distributors “err on the side of caution with DER Pricing” (see paragraphs 185-188 of Distribution pricing practice note). We now consider that a more progressive approach is justified, and plan to update this section of the DPPs accordingly.

How to calculate avoidable LRMC

5.6. The "LRMC" refers to the average cost, over the long term, of an additional unit of demand from a consumer in the relevant consumer group and pricing region, that occurs when demand is "peaking" and therefore driving future network costs.

5.7. As Orion's 2025-26 pricing methodology states, "our estimates of LRMC include those components of forward-looking network expenditure that could be avoided through a change in the timing of consumption or generation."[43] This figure is expressed in dollars per kilowatt of peak demand per year ($/kW/yr).

5.8. There are various established methods of calculating this LRMC (most notably the 'average incremental cost approach' and the 'perturbation approach'[44]) which we expect distributors to use in their pricing methodologies, subject to the transitional arrangement for the first pricing year discussed below. We also understand that ENA has developed tools to assist distributors with these calculations.

5.9. Because it is an averaged figure, the avoidable LRMC from the average injection from a whole consumer group will likely be lower than the avoidable LRMC relating to a specific constrained asset. This is because the average LRMC takes into account the fact that some injection (from the relevant consumer group in that pricing region) may occur on unconstrained parts of the network and therefore may not provide much/any value.

5.10. The avoidable LRMC may be lower on a network where the distributor procures contracted flexibility. This is because an additional unit of demand will not (on average) cause the same degree of network investment pressure, as the contracted flexibility will be used to manage specific constraints. Distributors that procure contracted flexibility may therefore set a smaller rate for their negative charges for injection generally (ie, including uncontracted injection), as the average LRMC savings from this injection will be lower.[45]

5.11. Even if the injection does occur where required, pricing may not incentivise enough injection to defer an investment. Therefore, as noted by Horizon Energy, this means that "contracted flexibility … justifies a premium above a price-based response that relies on a minimum assumed response."

5.12. Where a pricing region[46] is not facing demand growth and therefore not facing any demand-driven constraints, the LRMC of demand will be zero, even at peak times. Injection in such regions therefore does not avoid any network costs, so there should be no negative charges for injection.

5.13. Similarly, the LRMC of demand outside peak times is likely to be zero, as additional consumption at this time will not drive future network upgrades. The Authority's recent open letter to distributors noted that this means distributors' variable charges for consumption during these times should also be set at (or at least near) zero. In the same way, injection during these times will not help avoid any future network

[43] Powerco's cross-submission also noted that its "export rebates are based on the same long-run marginal cost of network augmentation planned in our AMP by pricing region".
[44] We note the 'perturbation' approach is sometimes known as the 'marginal incremental cost' approach.
[45] As noted by EA Networks, "a pricing and flexibility package could work in tandem, but we'd need to be careful that the combined reward didn't exceed lead [sic] to higher costs for our customers than the network solution that we are looking to avoid or delay".
[46] Or even an entire network in some cases – for example, Westpower notes that on its network, "any capacity constraints are likely to be some time away".

costs, so injection pricing should also be set at zero (unless the injection creates additional costs, as discussed below).

5.14. In some cases, injection during off-peak times could *drive* additional future costs, for example if there is a lot of injection in a pricing region from uncontrolled solar during the middle of the day, which requires network investment to manage voltage. In such cases, it would theoretically be efficient for distributors to *charge* for peak injection, rather than pay for it.[47] As noted above, several Australian distributors have implemented this kind of charge in their 'two-way' tariffs.

5.15. However, we do not expect this to be necessary (at least in the near term) for most New Zealand distributors.[48] Current solar penetration is fairly low, particularly compared to Australia. As with the LRMC of peak demand, any injection charge would need to be based on the average LRMC of injection at those times across the consumer group and pricing region; a single instance of injection causing network costs doesn't mean that there is a material long-run marginal cost for injection across the whole price category. We therefore consider that the principles do not mandate peak injection charges, but note this here for completeness.

5.16. Some distributors may not currently have the capability to calculate the average LRMC of peak demand that injection can avoid. The principles therefore include a transitional measure allowing distributors to base their negative charges on the consumption pricing differential for the first pricing year (discussed in more detail from paragraph 5.28). Where distributors take this approach, they will not have to publish the LRMC of peak demand in their pricing methodology for the first pricing year.

How to structure negative charges for injection

5.17. Distributors must then turn this LRMC figure into a negative charge for injection. As with consumption pricing, negative charges for injection could take several forms. Options include:

(a) **Fixed period pricing** (eg, time of use) – the distributor identifies defined times during which the negative charge applies. Any injection during these periods receives a payment/credit on a $/kWh basis. These periods should reflect when demand is most likely to peak (and therefore drive future investment). They should therefore generally overlap with the distributor's peak period for their time of use consumption charge (noting that the injection period could be more narrowly targeted than the equivalent consumption period to account for the fact that injection has characteristics that may justify a more accurate/less simplified approach than consumption – see discussion

[47] Counties Energy submitted that "the principles should also enable EDBs to include 'cost' pricing signals to manage network constraints caused by too much injection, at certain times of the day, or certain areas of the network." We agree, noting that there is nothing preventing distributors from implementing such price signals (either in the new principles or under the status quo). It would also be efficient to encourage consumption during these times. This is already done to a large degree by low (or zero) consumption rates during these times, but theoretically it could be efficient to pay for consumption at these times (ie, negative charges for consumption).
[48] Two distributors' (Counties Energy and Waipā Networks) submissions included examples of where injection had resulted in additional network costs.

at paragraphs 4.41 to 4.43).[49] We expect this method to be the easiest to implement, and therefore the most common way to apply a negative charge.

(b) **Control period pricing** – the distributor identifies circumstances during which the negative charge applies (for example, any period during which the distributor is controlling hot water load on its network). Any injection that occurs during such periods receives a payment/credit, either on a $/kWh basis or a $/average kW basis (which are effectively the same in practice). This kind of pricing structure is typically found in consumption pricing for larger distribution customers, so we do not expect it to be widely used for injection pricing for mass market customers.

(c) **Controlled pricing** – the distributor is granted control rights over the battery (or other flexible generation) so they may choose when it injects into the network. Distributors may pay for this injection through a general discount to the consumer's lines charges, or by paying specifically for any injection that occurs as a result of this control. This would be similar to how distributors charge lower consumption charges for the ability to control consumers' hot water loads. We note that we are not aware of any distributors that have direct control over consumer batteries at present (other than through contracts with retailers or aggregators), so this kind of 'negative pricing' may be uncommon or unlikely to arise at all, but we note it here for completeness.

What to consider when converting LRMC into a negative charge for injection

5.18. When converting LRMC into a negative charge for injection (eg, setting the precise rate and circumstances at which the negative charge will apply), distributors must take into account transaction costs, consumer impacts, uptake incentives and network stability. These principles are slightly different from our initial proposal – they have been amended to better reflect considerations discussed in the DPPs.[50]

(a) **Transaction costs** – while distributors should generally aim to make distribution pricing more cost-reflective, as noted above there is a trade-off between accuracy and simplicity. More accurate prices, for instance through more granular pricing regions or narrower/more dynamic pricing periods, come with higher transaction costs. As noted in the distribution pricing practice note, transaction costs can include direct costs (such as upgrading billing systems) or more intangible costs (such as the cost to consumers of interpreting and understanding prices). Distributors should not set negative charges at a degree of granularity that causes transaction costs to outweigh the benefits.

(b) **Consumer impacts** – distributors should be conscious of how changes to pricing are likely to affect consumers. As set out in the distribution pricing practice note, "price shocks are not a desired outcome of pricing reform, and the Authority is cognisant of the need for prices to evolve on a journey

[49] For example, Powerco's negative charge applies only in winter, while their consumption charge also applies in summer and Essential Energy's negative charge applies from 5pm-8pm, whereas their peak consumption charge applies from 3pm to 10pm.

[50] We note that Powerco's submission suggested that "it may be helpful to clarify that the principles are consistent with the Authority's distribution pricing principles and the implementation guidance provided in its Distribution Pricing Practice Note." We state this explicitly at paragraph 5.5, and also consider that amending these principles to better align with the DPPs will reinforce this consistency.

towards efficient outcomes, rather than rush to an endpoint." This may mean setting a negative charge at a relatively conservative rate initially, which increases over time, rather than setting it too high and discovering it needs to be lowered. Having regard to consumer impacts may also involve considering the degree to which injection pricing shares the benefits of peak injection with non-injecting consumers (if the full value of avoided LRMC is paid to injecting consumers, there may be no surplus value for consumers generally).[51]

(c) **Uptake incentives** – because negative charges for injection are paid to retailers, the price signal may be repackaged before being passed through to consumers.[52] As with consumption charges, distributors should consider how effectively the price signal in their negative injection charges can be passed through to end consumers. If distribution charges are too granular, complex, volatile, or don't align easily with wholesale price signals, retailers may be less likely to pass them through efficiently. Distributors should consider this when determining how targeted and dynamic their pricing should be. Equally, too low a signal may not result in retailers considering it worth passing through.

(d) **Network stability** – as discussed above, injection at the wrong time/place may not only provide no network benefits, but may incur additional network costs (ie, a negative benefit) by causing localised export congestion or voltage issues. Accordingly, despite not being an explicit consideration under the DPPs, distributors should consider whether (and if so when and where) a negative charge may lead to excess injection. If so, they should consider steps to mitigate this risk. This will likely result in a negative charge that is more targeted and/or applies a lower rate than the equivalent consumption charge.

5.19. Distributors' pricing methodologies must set out how they have calculated the LRMC of peak demand and how they have converted this to a negative charge, including their underlying considerations and assumptions.

Distributors must comply with these principles from the pricing year beginning 1 April 2026

What we proposed

5.20. We proposed requiring distributors to implement the principles by 1 April 2026, which aligns with the start of the 2026-2027 pricing year. This balances the need to address the missing distribution price signal for injection with the practical realities of amending distribution pricing outside of the annual cycle.

What submitters said

5.21. Most distributors considered implementing the original proposal by this date would be unworkable, or at least very difficult. They noted that:

[51] As noted by ETNZ, "a portion of the saving should be reserved for customers. Transferring the full value of the benefit from one group to another will not result in lower customer bills."
[52] Under Task Force initiatives 2B and 2C, retailers will have to offer at least one time-varying consumption plan and one time-varying injection plan. We expect this to improve the extent to which distribution signals are passed through, but note that retailers will still be able to repackage these price signals so that they are more suitable for consumers.

(a) Granular pricing would involve substantial work to implement (improving data access, billing systems, modelling benefits, etc.).[53]

(b) There will be very little time between the Authority's decision (July 2025) and the time when price setting begins (September 2025) for this work to occur.[54]

(c) Distributors' resources are limited, particularly smaller distributors, and a lot of this is being taken up by connection pricing and other regulatory reform.[55]

(d) Low Fixed Charge regulations, which limit distributors' abilities to offer cost-reflective pricing, will not be entirely phased out until 2027-28 pricing year.[56]

5.22. On that basis, many distributors proposed that implementation should be pushed back to 1 April 2027. Alternatively, some submitters suggested implementing the principles on a trial basis or including a sunset clause or automatic review mechanism.[57]

5.23. On the other hand, some submitters (largely consumer-focused submissions) supported the proposed implementation timeframe.[58]

5.24. Some distributors also asked for clarity as to whether a Code amendment that would "come into effect on 1 April 2026" would affect pricing methodologies for that year, or only the following year.[59]

Our response

5.25. We would like to clarify that our intent has always been for the Code amendment to apply to pricing methodologies starting from the beginning of the 2026-2027 pricing year. The Code itself has been amended with the publication of this decision paper.

5.26. Having considered submissions, we agree that the original proposal would be difficult to implement in the proposed timeframe, particularly alongside concurrent pricing reform.

5.27. However, we have changed the original proposal to remove the requirement to calculate specific benefits caused by deferral of specific investments. Accordingly, we consider it will be manageable for distributors to introduce this simpler form of negative charge by 1 April 2026, as they will not have to set individual pricing for every constrained asset in their network. We note that several submitters noted that a simpler proposal would be quicker and easier to implement.[60] Such a timeline

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[53] For example, Aurora Energy, EEA, Horizon Energy, Orion, PowerNet, Wellington Electricity, Westpower.
[54] For example, Aurora Energy, Northpower.
[55] For example, Alpine Energy, ENA, Horizon Energy, Northpower, Vector.
[56] For example, Aurora Energy, Mainpower/Marlborough Lines. Powerco agreed with the proposed timeline, but noted "the low user fixed charge will not be removed until 1 April 2027. This is a major distortion to distribution pricing, which will evolve in the 2027-2028 pricing year as a result. Export rebates should evolve in the same way."
[57] Alpine Energy, ENA, Lastmyle Limited, Mercury, Network Tasman, Orion, The Lines Company.
[58] For example, Neil Walbran Consulting, Nu'uli'itia Andrew Redwood, and Powerco. Graeme Weston submitted that the timeline should be accelerated where possible.
[59] Horizon Energy submitted that "if the proposed Code amendment comes into force on 1 April 2026, it would not impact the 2026-27 pricing year, as pricing methodologies will have been set and published on or prior to 31 March 2026." ENA made a similar point.
[60] Rewiring Aotearoa (and many consumer submissions) noted that symmetrical export tariffs would be easier to implement within the proposed timeframe. Additionally, as referenced in footnote 25, Powerco, Unison/Centralines, and the Ofgem paper referenced in Counties Energy's cross-submission all noted that less granular pricing would be easier to implement.

also ensures that distributors will act in a timely way to address this missing distribution pricing signal.

5.28. The Authority does accept that it may still take some time for distributors to collect the necessary data and establish the processes required to properly calculate the LRMC of peak demand that could be avoided by injection at these times. Given this, the Code amendment provides for a transitional arrangement that allows distributors to base their negative charges for the first pricing year on the differential between the distributor's peak and off-peak rates – ie, on the assumption that this differential broadly reflects the network LRMC.[61]

5.29. This transitional arrangement has some similarities to the 'consumption-linked injection rebates' alternative option considered in our consultation paper. However, we note that the transitional arrangement is:

(a) principles-based – distributors retain the flexibility to adjust the peak/off-peak differential when setting their negative injection charge, so as to reflect their individual network circumstances;[62]

(b) optional – distributors that can or already do calculate an evidence-based LRMC (eg, through the average incremental cost or perturbation method) for the first pricing year are encouraged to base their negative injection charge on this; and

(c) time-limited – in subsequent years, distributors must base their negative charges on the LRMC they have calculated using an evidence-based approach, rather than on their consumption charges.

5.30. We do not consider that the amendment affects the operation of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. Any impact of applying negative charges in respect of injection will be neutral in terms of how distributors are to determine charges for domestic consumers under the regulations. The Code amendment also requires that if a distributor is using the transitional measure, it must base its negative charges on the differential between its peak and off-peak consumption charges, which are not regulated under these regulations. This approach is used as consumption charges that are not regulated under these regulations are more likely to be cost-reflective.

[61] If a distributor's pricing is cost-reflective, its pricing should reflect the impact of additional demand on future network costs. During peak times, pricing should reflect the LRMC of additional peak demand, while during off-peak times pricing should be at or close to zero. Costs that are not demand-driven should be recovered in the least distortionary way (eg, through fixed charges). However, we note that some distributors still recover some fixed costs through their variable charges, therefore the LRMC is best reflected in the differential between their peak and off-peak charge, rather than just the peak charge itself.

[62] We agree with Aurora Energy that "consumption-linked injection tariffs and a principles-based approach are not mutually exclusive. For example, use consumption-linked injection tariffs as a baseline for setting export tariffs. Then, apply principles-based adjustments to account for specific network conditions, such as local constraints and peak demand periods. This ensures that tariffs are both cost-reflective and adaptable to changing conditions."

A principles-based approach gives distributors flexibility

What we proposed

5.31. We proposed a principles-based approach on the basis that it "would give distributors flexibility to make payments for injection in ways that best suit their network, taking into account individual network circumstances".

5.32. We also considered a more prescriptive option that would set out where, when and how negative charges must apply. However, we considered that such a centralised prescriptive approach would create "a risk that the Authority prescribes requirements that are impractical, inefficient, or hampered by information asymmetries."[63] Given this, we did not prefer this prescriptive option.

What submitters said

5.33. Submitters generally agreed that a principles-based approach was preferable, because, as set out in the consultation paper, it provides more flexibility, is more workable, and reduces the chance of unintended consequences.[64] For example, Counties Energy supported this option because it "allows EDBs to decide the quantum of network benefit that an injection price signal provides against the practicalities of implementing such an option".

5.34. Some submitters, while supportive of a principles-based approach, considered that some structured guidance could be useful. For example:

(a) Octopus Energy noted that it "would like to see some mandated structure around how rebates are delivered. These should be part of the EDB's regular tariff structure and included in the monthly invoicing and market reconciliation. We do not support less frequent rebates or discount processes, such as already occur once or twice a year for a few networks and are time-consuming for retailers and lack transparency for consumers."

(b) Waipā Networks believed "there would be benefit in the Authority developing a methodology and associated prescribed rates for EDBs to use for guidance purposes."

5.35. Other submitters disagreed, preferring a more prescriptive approach. In particular, Rewiring Aotearoa and many consumers were concerned that monitoring and enforcement would be light-handed and slow, and considered these issues could be resolved by a prescriptive symmetrical export tariff approach. They also argued that the principles were "so permissive that it is unlikely that an EDB would be found non-compliant except in the most egregious circumstances". SEANZ also did not prefer a principles-based approach, as it considered that "prescription can drive consistency".

Our response

5.36. We continue to prefer a principles-based approach, for the reasons discussed above.

[63] Consultation paper, paragraph 5.31.
[64] Aurora Energy, Counties Energy, EA Networks, EEA, ENA, ERANZ, Genesis Energy, Graeme Weston, Horizon Energy, Lastmyle Limited, Meridian Energy, Neil Walbran Consulting, Orion, Powerco, PowerNet, The Lines Company.

5.37. We accept that a principles-based approach can make monitoring and enforcement less objective and therefore more time consuming. However, we note that this is a new area of pricing development for most distributors, and therefore some degree of pragmatism is warranted. A principles-based approach (when codified, as discussed in the following section) will ensure that distributors implement negative pricing for injection at a reasonable pace, while giving the Authority some enforcement discretion. The Authority would not be comfortable taking a more prescriptive approach without first ensuring that any unintended consequences for distributors had been comprehensively worked through, which would likely result in the amendment (and ultimately, the consumer benefits it brings) being delayed.

The principles will be codified

What we proposed

5.38. We proposed that the principles be codified, to enable the Authority to "enforce compliance, which should result in a stronger and more urgent response from distributors."[65]

What submitters said

5.39. Consumers and consumer groups tended to support codification, on the basis that voluntary principles are not sufficiently enforceable and may lead to inconsistent implementation between EDBs. For example, Rewiring Aotearoa argued that codification was "necessary for it to be picked up consistently by EDBs to address the problem and for EDBs to act on reasonable timelines."[66]

5.40. However, most distributors (and several other submitters) preferred that the principles be voluntary, on the basis that:

(a) Regulation needs to be able to adapt quickly.[67]

(b) The proposed principles would be hard to implement, so pragmatism would be useful.[68]

(c) Consumption pricing is regulated by voluntary principles.[69]

5.41. Some distributors considered that principles should be voluntary initially, with the intent to codify either in a more appropriate timeframe or only if satisfactory progress is not observed.[70] The EEA suggested referencing the principles in the Code but leaving the details in voluntary guidance outside the Code.

Our response

5.42. We remain of the view that the principles should be codified. As discussed in our consultation paper and supported by many consumer submissions, it is important that the Authority has the ability to enforce compliance under the Code.

[65] Consultation paper, paragraph 5.2.
[66] Neil Walbran Consulting, Octopus Energy, Powerco, SEANZ, and many consumer submissions made similar points.
[67] For example, EA Networks, ENA, Genesis Energy, Meridian Energy, Network Tasman, Orion, Unison/Centralines and WEL Networks.
[68] For example, Aurora Energy, ERANZ, and Mainpower/Marlborough Lines.
[69] Horizon Energy noted that it believes "the Electricity Authority's work on the distribution pricing principles (which sit outside of the Code) has been successful in lifting all EDB's approach to pricing".
[70] Network Tasman, PowerNet, Waipā Networks and Wellington Electricity.

5.43. Because the Code amendment is principles-based, we consider that it still provides the necessary flexibility for distributors to adapt their responses as circumstances change, and allows the Authority some flexibility when applying its interpretation for compliance purposes.

5.44. We recognise that the consumption pricing remains subject to voluntary principles only. The Authority considers that real progress has been made in that space, but that it has taken time. We want to ensure that injection pricing does not continue to lag behind consumption pricing reform, and we consider that stronger regulation is required to achieve this.

The principles will apply to injection from mass market customers only

What we proposed

5.45. We proposed that the principles would apply to mass market customers only. These would be achieved by identifying ICPs that are subject to 'standard contracts'.

What submitters said

5.46. There was wide support for only applying the principles to mass market customers, as larger customers on bespoke contracts are more likely to be able to negotiate pricing that rewards their injection for the benefits it provides.[71] Wellington Electricity also submitted that contracted flexibility is better suited to large distributed generators, whereas price-based flexibility is better for mass market customers.

5.47. However, some of these distributors noted that the term "standard contracts" in the proposed Code drafting was wider than intended and would include many larger customers that were not intended to be in scope.[72]

5.48. Other submitters considered that the principles should apply to all customers to ensure a level-playing field, or because larger customers are likely to be able to make a greater contribution to reducing net peak demand.[73]

5.49. Many consumer submitters argued in support of Rewiring Aotearoa's preferred solution (symmetrical export tariffs) and considered this solution should apply to all customers regardless of size.

Our response

5.50. Like many submitters, we remain of the view that the principles should apply to injection from mass market customers only. As noted in our consultation paper, we consider that under the status quo, larger customers are *already* more likely to be rewarded for any benefits their injection provides, as they can negotiate this in their pricing agreement. Mass market customers do not currently have this bargaining power, so we consider our amendment will put these customers on more of a level playing field, rather than distorting it.

[71] Alistair Gardiner, Aurora Energy, Counties Energy, EEA, ENA, ERANZ, Firstlight Network, Gavin Treadgold, Genesis Energy, Horizon Energy, John Hilhorst, Meridian Energy, Neil Walbran Consulting, Octopus Energy, Orion, Powerco, PowerNet, The Lines Company, Waipā Networks, Wellington Electricity.
[72] EA Networks, WEL Networks.
[73] Ecotricity, Graeme Weston, Lastmyle Limited, Mainpower/Marlborough Lines, SEANZ.

5.51. We agree with the terminology concern raised by some distributors, and have therefore changed our Code amendment so the principles now apply to "any price category that has eligibility criteria that are designed to target residential or small business consumers", rather than to those on "standard contracts".

The principles should apply to injection from any kind of distributed generation or storage (provided it occurs at peak times)

What we proposed

5.52. We proposed that the principles should apply to injection from any kind of distributed generation/storage (provided it occurs at peak times).

What submitters said

5.53. Submitters generally agreed that the principles should apply to all generation/storage, including inflexible generation.[74] However:

(a) Many stressed the importance that, regardless of the generation/storage type, payments should only be required where injection provides network benefits.[75]

(b) Some considered that, in practice, inflexible generation would provide no benefits at all, so would not be eligible for any payments.[76]

(c) Waipā Networks noted the importance of clear communication to consumers that inflexible generation would be unlikely to receive any payments.

(d) Orion considered that thermal generation should be explicitly excluded.

5.54. EA Networks noted that identifying the precise source of injection could be difficult, as "we often see a mix of generation, and we are not in a position to rank each as flexible or inflexible".

Our response

5.55. Like many submitters, we remain of the view that the principles should apply to any kind of generation/storage. Distribution pricing should be technology agnostic, and reward injection for the benefits it provides regardless of the underlying technology. We also agree with EA Networks' point that requiring distributors to distinguish between different sources of injection could have workability challenges.

5.56. We disagree that inflexible generation provides no benefits at all. While this kind of injection may not be certain enough to defer specific investments, we consider that (as noted at paragraph 4.27) it can provide broader benefits over the long term, after diversity of supply is taken into account.

5.57. However, under the principles the negative charge must apply at times when demand in the relevant pricing region "is likely to, on average and over time, drive future network investment". It is therefore unlikely to apply to injection from solar

[74] For example, Alistair Gardiner, Aurora Energy, Ecotricity, ERANZ, Gavin Treadgold, Genesis Energy, Graeme Weston, John Hilhorst, Lodestone Energy, Meridian Energy, Octopus Energy, Powerco, PowerNet, The Lines Company, Waipā Networks, and Wellington Electricity.

[75] For example, Counties Energy, EEA, Lastmyle Limited, Neil Walbran Consulting and SEANZ.

[76] For example, ENA considered that "it is unlikely that inflexible generation will meet the criteria to generate a rebate payment." Firstlight Network, Horizon Energy, WEL Networks and Westpower made similar points.

during the middle of day.[77] In most cases, the negative charge will only apply to injection that occurs during morning or evening demand peaks, which will generally require some kind of battery storage (particularly if the relevant injection pricing periods are more targeted than peak consumption periods). We agree that it is important that this is clearly communicated to consumers.

5.58. We consider that this will incentivise consumers to shift their injection towards peak times without mandating how this is done. While in most cases we expect this will be through installing a home battery, it could also include installing solar panels on steeper angles to generate more in the early morning or evening, or installing other flexible generation.

[77] Unless the distributor identifies a pricing region where future investment is driven by demand in the middle of the day, such as where the primary source of peak demand is from irrigation.

6. Submissions raised other points that required consideration, but do not change our decision

6.1. This section sets out key issues raised in submissions that warrant further discussion. However, our view is that they do not change our decision to codify principles requiring distributors to introduce negative charges based on the long-run marginal cost of demand that injection can help avoid.

Symmetrical export tariffs are not the preferred solution

Context

6.2. Rewiring Aotearoa previously published a report on why it believes symmetrical export tariffs (SETs) would be a good way of addressing the missing distribution price signal for injection that can benefit the network, and ultimately, consumers.[78] That option would require distributors to apply negative charges for injection that mirror peak consumption charges (both in terms of the rate paid, and when and where it applies).

6.3. Our consultation paper included an alternative option of 'consumption-linked injection tariffs'. This used the same general logic that, just as demand response during peaks can be beneficial to the network, injection during peaks can benefit the network too. However, we consider there to be some differences between demand response and injection, and our consumption-linked injection tariff option would therefore have allowed distributors to apply a lower (and potentially more targeted) negative charge than the equivalent consumption charge (ie, not symmetrical).

What submitters said

6.4. In its submission,[79] Rewiring Aotearoa noted that SETs are still its preferred solution. It argued that SETs:

(a) are simpler to understand, implement, regulate and update. They are prescriptive, so do not rely on qualitative judgements that could make enforcement difficult.

(b) treat consumers with distributed generation/storage more fairly, as during peak times, a consumer reducing their demand had the same effect on the network as a consumer injecting into the network. Its submission stated that:

> *"The value of peak reduction is clearly defined by a network's peak consumption pricing - that is, reducing consumption by 1kWh is worth X cents to a home (the peak rate). Which is to say that the extra electricity made available to the network by the consumer reducing demand is worth the same X cents. Yet when a home reduces its demand to below zero, that is it starts to provide energy back to the network (and in practice, to their neighbour), suddenly the value is deemed as less by the Authority?"*

[78] More recently, Rewiring Aotearoa also introduced its 2025 Policy Manifesto, which also advocates for SETs.
[79] As well as in submissions from consumers and other consumer groups that used Rewiring Aotearoa's submission template.

(c) will encourage consumption pricing to become more cost reflective. Its submission noted that:

> *"Requiring injection pricing to mirror consumption pricing will provide a significant incentive to distributors to undertake pricing reform and make their consumption (and therefore injection) pricing significantly more cost reflective".*

Our response

6.5. We agree with much of Rewiring Aotearoa's submission on this issue. In particular, we agree with their view that:

(a) there is a missing distribution price signal for injection at peak times;[80]

(b) there are significant distribution benefits to be gained from more distributed flexible generation/storage on the network;[81] and

(c) broad price signals for injection are justified.[82]

6.6. However, SETs are not our preferred solution. In explaining our rationale for this, we address Rewiring Aotearoa's three main arguments noted above.

6.7. Firstly, we agree that SETs would be simple to implement, particularly compared to our original proposal (ie, targeted pricing). However, we consider that our revised principles will also be relatively simple to implement. As with SETs, they do not require distributors to implement highly granular pricing (ie, assessing a multitude of individual constraints at various network levels), but allow distributors to implement broader negative charges at the pricing category level.

6.8. Secondly, we disagree that SETs would be the fairest solution. We agree with the general logic that injection during peaks can benefit the network in similar ways to reducing consumption, and that there is value in rewarding both through a broad price signal. However, we consider injection has two defining characteristics that justify setting injection pricing at a lower rate and in a more targeted way than consumption pricing:[83]

(a) Injection can cause additional costs to the network that demand reductions do not. As noted in our consultation paper, "if injection is over-incentivised, it could cause export congestion or voltage issues at certain parts of the network that require additional investment to avoid damaging network infrastructure." This would increase, rather than decrease, the total network costs ultimately paid by consumers. Taking this risk into account, the average value of injection to the network is likely to be lower than the average value of

[80] As noted in its report, "as soon as a household with solar and battery moves from consuming to exporting, the network tariff vanishes".

[81] In its submission, Rewiring Aotearoa noted that "the potential savings from more injection reducing or deferring a large proportion of network investment is therefore well beyond substantial".

[82] In its cross-submission, Rewiring Aotearoa noted that "when *charging* consumers for peak consumption, the peak charge is broadly applied across large swathes of the network, regardless of individual location based network constraints. In some ways, this methodology is understandable, as much more locationally cost reflective pricing in this regard may see one street with no peak price, and another street with a large peak price. This would confuse customers, and create a yoyo effect on pricing as network constraints appear in varying places. Yet even though EDB's comfortably charge customers in broad ways that are not necessarily cost-reflective, they rally against crediting customers with that same methodology."

[83] Both these key characteristics of injection were outlined in our consultation paper, but Rewiring Aotearoa's submission did not materially address these points.

demand response. Several submissions supported this point. Orion noted that "generation can fix thermal constraints, but may create or exacerbate voltage constraints. For example, solar generation in a residential area may reduce loading on a transformer during summer (beneficial), but simultaneously cause voltage rise issues that may require additional network investment to manage (detrimental)".[84] As such, distributors would be justified setting a lower rate for injection pricing on the basis of network stability.

(b) Injection at peak times (which will most likely come from battery storage) is likely to be more responsive to price than demand response.[85] As noted by Counties Energy, "the price elasticity of demand response is likely to be lower than injection, as demand during the day is driven by routine or commercial activities, which is less 'shiftable'." This can lead to issues such as 'battery dumping' – as Aurora Energy noted, "when stored energy is released all at once at the start of a congestion period, it can create significant issues." Cost-reflective distribution pricing involves finding a balance between accuracy and simplicity, but we consider that this characteristic justifies setting injection pricing at a different point on this continuum – ie, targeted to narrower time windows when the network's maximum demand is most likely to occur.

6.9. Finally, while we agree with Rewiring Aotearoa that SETs would eventually encourage distributors to make consumption pricing more cost-reflective, we consider this approach could have unintended consequences in the short term. For instance, if a distributor has consumption pricing that is not very cost-reflective (ie, high variable charges at peak times to recover fixed costs) when the SET comes into effect, its initial negative charge for injection may be very high, leading to an over-investment in batteries where network benefits are limited.[86] Furthermore, while the distributor may make their consumption pricing more cost-reflective for subsequent pricing years (reducing the amount they must pay for injection), consumers may have already invested in battery systems based on the initial high injection payment, only to have this revenue stream reduced.[87]

6.10. For the reasons outlined above, the Authority continues to hold the view that SETs are not a preferred solution for the interests of all consumers.

Many other measures suggested by submitters are already underway

What submitters said

6.11. Some submitters considered that the Authority should prioritise other reform ahead of distribution pricing for injection. Such reforms would help enable more contracted flexibility, and are discussed above from paragraph 4.25.

6.12. However, other wider reform was also suggested. In particular, submitters recommended the Authority prioritise:

(a) Wholesale market reform;[88]

[84] Counties Energy agreed that "network export capacity [is] nearly always […] constrained on a voltage basis rather than the thermal rating of the network assets."
[85] See previous discussion from paragraphs 4.39 to 4.43.
[86] We note that Ausgrid in Australia initially trialled a fully symmetrical tariff, but has since reduced the rate paid for injection, noting that its customers on the trial tariff were "on aggregate recipients of a cross-subsidy."
[87] The importance of relatively stable price signals is discussed at paragraph 4.33.
[88] For example, Nu'uli'itia Andrew Redwood, Pulse Energy, The Lines Company.

(b) Retail market reform (e.g. mandatory pass through of distribution pricing, mandating wholesale export prices, best plan notices, and peer-to-peer trading);[89]

(c) Educating consumers about switching and investment decisions;[90]

(d) Reviewing voltage regulations and distributors' export capacity limits;[91]

(e) Advocating EECA/MBIE to introduce government subsidies, etc. for certain types of distributed energy resources;[92] and

(f) Considering how to address other rising costs faced by distributors (e.g. traffic management, vegetation management, insurance).[93]

Our response

6.13. We note that some of these proposed areas of reform are already the subject of consideration under the Task Force's work programme:

(a) Wholesale market reform is being considered as part of the first package of Task Force initiatives.

(b) Retail market reform is occurring as part of the 2B and 2C initiatives that are being released in parallel.

6.14. The Authority also continues to work on improving the resources available to consumers to help them make good switching and investment decisions. For example, we released a decision paper in July last year on "Supporting consumers to compare and switch electricity plans."

6.15. Capacity limits will be considered in stage 2 of the Authority's Network Connections project.

6.16. Other reform is out of scope for the Authority and would sit with other regulatory bodies such as MBIE or local government. We note that MBIE recently announced it is "expanding the permitted voltage range for New Zealand's electricity networks and making changes to the building consent process to help increase the uptake of residential solar".

The Code amendment will only incentivise distributed generation/storage beyond what is used to offset a consumer's own demand

What submitters said

6.17. Several submitters commented that the proposal would be ineffective as the potential revenue is far too low to incentivise consumers to invest in batteries that would allow them to inject at peak times.[94] Much of this was based on the analysis presented in

[89] For example, SEANZ, Unison/Centralines, Utilities Disputes.
[90] The Lines Company noted specific areas where education is required include "ensuring customer solar and battery investments are efficient and investments are not as a result of a sales pitch", "ensuring customers know that any rebate available now may not be available or applicable in the future" and "educating customers about switching and making this simpler". FlexForum made a similar point.
[91] For example, Electrify Wanaka, Roland Nash and SEANZ.
[92] Orion noted that this could include "capital grants, subsidies, or rebate schemes specifically for battery storage systems, smart inverters, home energy management systems, and other technologies that enable active participation in flexibility markets."
[93] PowerNet noted it considered these to be "far greater areas of impact and material difference for EDBs".
[94] For example, Alistair Gardiner, ENA, ERANZ, ETNZ, Orion, PowerNet, Waipā Networks.

Appendix A of the consultation paper, which suggested annual payments averaging only around $6 under the ‘consumption-linked injection rebate’ option.

6.18. On the other hand, Rewiring Aotearoa’s own analysis in their submission noted that a symmetrical export tariff could result in annual payments of around $175.

Our response

6.19. Firstly, we note that the negative charge does not need to be a strong enough incentive to encourage battery investment on its own. As noted by Ecotricity, “while the rebate should be material enough to act as a driver for behavioural change, it should be seen as part of a larger value stack.”[95] Battery investment can also be driven by other sources of value, such as:

(a) cheaper energy – using energy from less expensive sources (eg, from home solar generation or from the grid at off-peak times) to meet the consumer’s demand at times that energy is more expensive;

(b) cheaper lines charges (for consumption) – reducing net consumption at peak times, thereby reducing the amount paid under the distributor’s peak charge;

(c) resiliency benefits – being able to use electricity when the network is down, such as after severe weather events; and

(d) environmental benefits – some consumers value the (non-financial) benefit of being able to power their home at peak times using their own renewable generation, minimising their use of the grid at peak times when the generation mix tends to contain power from fossil-fuelled generation.

6.20. In saying this, we do accept that the modelling in our consultation paper suggests very small payments for consumers with batteries. However, we note that the purpose of this modelling was only to show the estimated *short-term* impacts of the proposal on consumers *without* batteries. It was based on standard battery sizes (operating one cycle per day and perfectly offsetting peak demand) and average demand profiles. We initially refrained from estimating the financial reward that an individual consumer could expect to receive, as this figure is highly dependent on the amount that a consumer injects, which in turn depends on a wide range of variables, including battery size/mode of operation and demand profile (all of which may change as a result of the negative charge).

6.21. We note that Rewiring Aotearoa submitted that their symmetrical export tariff proposal would result in much higher payments for injection. Part of this is due to the negative charge being set at a higher (i.e. symmetrical) rate, but it also assumes a consumer will inject 40% of the battery's capacity during peak times, whereas our initial analysis assumed that, in the short term, the vast majority of the stored energy would be used to offset a consumer’s own demand.

6.22. This suggests that while the Code amendment may not provide strong additional incentives for most consumers to invest in smaller sized batteries that are mostly just used to offset consumers’ own demand, it is reasonable to expect it to encourage investment and behaviours that result in consumers injecting more energy into the network.

[95] Ecotricity also noted that the wider value stack “still requires serious sector attention”.

Negative distribution charges for injection are not a subsidy for solar/batteries

What submitters said

6.23. Some submitters were concerned about cross-subsidies. For example, Horizon Energy noted that "simply offering a volume-related price to DG where there is no guaranteed behaviour will create a cross-subsidy that increases the cost of electricity to consumers".[96]

Our response

6.24. While there may be some cross-subsidies in the short term between individual consumers, we do not expect any material cross-subsidies between consumer groups over the long term. This is because the amendment requires negative charges to reflect the benefits of injection that accrue "on average and over time":

(a) In the short term, consumers who inject at peak times will receive payment[97] even though this injection may not provide immediate benefits from deferring a specific network upgrade. Therefore, in the short term these payments will likely have to be funded from increased network charges for consumers generally, resulting in a cross-subsidy from non-injecting consumers to injecting consumers (although we expect this will be small).[98] However, over the *long term*, these payments should be more than recovered by network investment savings, which would *reduce* the amount otherwise needed to be recovered from consumers generally.

(b) Even over the long term, any individual consumer who injects may receive a payment that is higher or lower than the actual long-term benefit they provide. However, because negative charges should reflect the *average* benefits of injection from the whole consumer group, these "overs and unders" should cancel out. Individual consumers who are "overpaid" for the value of their injection will essentially be cross-subsidised by other individual injecting consumers who are "underpaid" for their injection. However, aggregated across the group (ie, on average), injection consumers as a whole should not be cross-subsidised by non-injecting consumers over the long term.

Distribution pricing and retail pricing are interlinked

What submitters said

6.25. The BusinessNZ Energy Council considered that retail pricing should be the primary tool to encourage behaviour change.

[96] ETNZ, Horizon Energy, Wellington Electricity and others made similar points.
[97] Technically, as noted previously, it is the retailer who pays distribution charges/receives any negative charges.
[98] Analysis in Appendix A of our consultation paper considered the short-term increase in average distribution charges for all consumers (including those without batteries) under a 'consumption-linked injection tariff' approach to be negligible. As discussed above, that analysis assumed current levels of battery penetration and average battery sizes, which result in little injection into the grid and therefore low payments to consumers with batteries. While individual consumers may be capable of higher levels of injection (resulting in higher payments), we consider that when total payments are spread across the entire consumer base, this cross-subsidy will still be small over the short term.

Our response

6.26. We agree that it is ultimately retail pricing that influences when consumers inject energy into the network. However, we note that retail pricing is affected by the price signals that retailers themselves receive. For instance, retailers have a financial incentive to offer retail plans that encourage consumers to use electricity when the wholesale value of that electricity is lower, as that affects how much retailers must pay to buy this energy in the wholesale market.[99]

6.27. Distribution pricing also affects retail costs, and therefore the incentives on retailers to offer plans with time-varying price signals. We consider that this Code amendment will provide the missing distribution incentive for retailers to offer plans that encourage injection at times when the network is facing demand-driven congestion (in addition to the existing wholesale incentive).[100]

There are key differences between this amendment and previous ACOT payment requirements

What submitters said

6.28. Some submitters were concerned that the proposal would result in similar issues to previous avoided cost of transmission (ACOT) payments.[101]

Our response

6.29. Under Part 6 of the Code, distributors are required to charge distributed generators no more than their incremental costs to the network.[102] Determining a generating customer's incremental costs requires "consideration of any identifiable avoided or avoidable costs", which previously included avoidable transmission costs. The old transmission pricing methodology included charges that were based on regional coincident peak demand (RCPD), and when a distributed generator reduced the distributor's net contribution to this peak demand, the distributor's RCPD charges were reduced. The distributor then had to pay the distributed generator these avoided charges as ACOT payments.

6.30. However, RCPD charges were inefficient because at the transmission level, congestion is already well-signalled in the wholesale energy market by locational marginal pricing. ACOT payments (which were based on avoided RCPD charges) were therefore also inefficient, as they rewarded avoided *charges*, but not necessarily avoided system *costs*.[103]

6.31. There is no locational pricing for energy at the distribution level. Distribution pricing is the only price signal available for managing congestion. Distribution pricing should therefore reflect actual costs to a much greater degree than RCPD charges

[99] We have identified several other factors that may be limiting the extent to which retailers offer consumers a broader range of price plans that provide meaningful price signals. We have addressed this in our decision on the Task Force 2B and 2C initiatives.
[100] It may also encourage retailers to take actions to maximise the amount they are paid by distributors for their customers' injection, for example, offering retail plans that involve the retailer controlling customers' batteries.
[101] ENA, Network Tasman, PowerNet.
[102] The Authority is currently considering reforming this provision.
[103] For this reason, the Authority clarified that ACOT payments were no longer required under the new transmission pricing methodology.

did. Similarly, negative charges for injection will reflect actual avoided costs more efficiently than ACOT payments.

The amendment should not fundamentally change income tax obligations

What submitters said

6.32. Some submitters queried whether payments would raise any tax implications for consumers or participants.[104] Some of these submitters considered that tax implications may change depending on whether the payment is a ‘rebate’ or a ‘negative charge’.

Our response

6.33. End consumers’ income, and therefore their income tax obligations, depend on any revenue or payments they receive from their retailer. These payments will likely reward injection for both the energy and any distribution network benefits it provides in a single payment.

6.34. Regulating distribution pricing (ie, payments between distributors and retailers, not to end consumers) may ultimately change the quantum of payments a consumer receives for their injection, depending on how retailers pass this through to end consumers. However, we do not expect any such regulation to change the income tax obligations in relation to those payments.

[104] Aurora Energy, ENA, PowerNet, Unison/Centralines.

7. Our decision supports our statutory objectives

7.1. This section sets out our view that our revised Code amendment supports the Authority's main statutory objective to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

7.2. It also supports the Authority's additional objective, to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers.

We expected our initial proposal to result in benefits that would support our statutory objectives

7.3. The main benefits of our initial proposal as identified in our consultation paper were the efficiency benefits from "reducing net peak demand and avoiding investments in more expensive traditional network solutions (ie, poles and wires) in the long term."[105]

7.4. We also identified reliability and competition benefits, although these were considered less material compared to the efficiency benefits.

7.5. We did not quantify costs or benefits because our proposed solution was principles-based, making net benefits highly dependent on how different distributors applied the negative charges, and therefore how much investment would be deferred.

7.6. However, we considered that these benefits would be material, and that costs would be low on the basis that:

(a) Many of the implementation costs (eg, establishing systems and improving network visibility) are likely to be incurred anyway as the distributor moved to more cost-reflective pricing.

(b) The targeted nature of our initial proposal would minimise the risk of over-incentivising injection (and the accompanying costs of this).

Some submitters disagreed with our assessment of net benefits

7.7. Many submitters queried whether the benefits of our initial proposal outweighed the costs. In particular:

(a) Multiple submitters were concerned that the modelled benefits of the initial proposal were low.[106]

(b) Other submitters considered that the implementation costs of the initial proposal were high, particularly due to its requirement for highly granular and targeted pricing.[107]

(c) Some submitters considered that a full cost-benefit analysis should be conducted before making this Code amendment.[108]

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[105] Consultation paper, paragraph 6.9.

[106] For example, Waipā Networks noted that "given we believe the actual rebates will be small both in terms of value and quantity, we don't believe the monetary benefits will outweigh the cost of implementation." Others made similar points – see paragraph 6.17 for a more detail.

[107] For example, ETNZ and Nova Energy. See paragraph 4.7 for more detail.

[108] For example, EEA, Lightforce Solar, Network Tasman.

7.8. We accept that the modelled financial impact in our consultation paper was low, but do not agree that this means the *benefits* of the amendment are low. As discussed from paragraph 6.17, this modelling does not reflect the estimated benefits of the 'consumption-linked injection rebate' proposal, but rather the estimated average amount paid by distributors to consumers with batteries in the short term under that option. In reality, some consumers would inject more than average into the network and receive a much higher payment, while others may only use their battery to offset their own load and therefore receive no injection payment.

7.9. Assuming our revised amendment results in negative charges of a roughly similar rate to those under a 'consumption-linked injection tariff' option, over time we expect the amendment will incentivise investment decisions and behaviour that lead to materially more injection at peak times, and therefore less investment required (on aggregate) to meet growing peak demand. While it may take some time for these benefits to materialise, we believe it is important to introduce these efficient price signals as soon as possible so that they can begin to shape investment and behaviour decisions from an early stage.

7.10. However, we do agree that implementation costs of the initial targeted proposal would have been relatively high, as the proposal would have required distributors to assess the specific benefits each ICP or group of ICPs could provide. As discussed from paragraph 4.17 above, we have removed the requirement for injection pricing to reflect the specific benefits of deferring a particular investment, and we consider that the costs of implementing broader price signals will be substantially lower.[109]

We consider our final amendment has higher net benefits

7.11. As a result, we consider that the Code amendment will have net efficiency benefits. Compared to our initial proposal, the final decision will have:

(a) benefits that are more generalised and accrue over the longer term, but remain material; and

(b) much lower implementation costs, as distributors are no longer required to base their negative charges for injection on the short-term benefits from specific groups of ICPs.

7.12. After considering all submissions on the Code amendment proposals, the Authority considers the final Code amendment is consistent with our main statutory objective, and with section 32(1) of the Act, being necessary or desirable to promote competition, reliability and efficiency, for the reasons discussed above.

7.13. We also consider that the amendment is consistent with our additional statutory objective, to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The amendment will improve these consumers' access to and uptake of price plan options that give them more choice about how they manage their electricity costs, in cases where distributors are dealing with these consumers directly.[110]

[109] As discussed in paragraphs 4.31-4.32, broader price signals are easier to implement with resulting lower costs.

[110] The additional objective only applies to the extent that distributors are dealing directly with domestic consumers and small business consumers. It does not apply generally to distribution pricing decisions, which are considered against the Authority's main objective as Authority decisions about distribution pricing do not generally involve dealings between participants and these consumers.

8. Next steps

8.1. The Authority has amended the Code to give effect to this decision.

8.2. The Code amendment will apply to pricing methodologies from 1 April 2026. Distributors must ensure that their pricing for the 2026-2027 pricing year complies with the Code amendment, and that the respective pricing methodologies reflect this.

The Authority will provide guidance on how distributors should calculate LRMC

8.3. The Authority will develop practical guidance to provide additional education for distributors on various ways that they could calculate the LRMC of new peak demand on their networks. This guidance will be useful for setting injection pricing (as required under this Code amendment) and consumption pricing (as encouraged by the 2019 DPPs).

8.4. We plan to publish this guidance and host accompanying workshops later this year. We accept that this is not in time for setting prices for the 2026-2027 pricing year, as price setting generally begins around September of the previous year. However, we note that the transitional arrangements in the Code amendment allow distributors who do not already have the capability to calculate LRMC to set injection pricing for that year based on the difference between peak and off-peak variable charges.[111]

Wider reform

8.5. The Authority will consider further additional reform that could help distributors procure more contracted flexibility in the future, including the potential options outlined at paragraph 4.25. We are still considering how to implement this process in our broader distribution network regulation workstream, but will provide more details as we have them.

[111] For the avoidance of doubt, distributors still have discretion to adjust the rate and granularity of their injection pricing when setting a negative charge for injection.

9. Attachments

9.1. The following appendices are attached to this paper:

Appendix A Code amendment

Appendix A Code amendment

~~**1.1 Interpretation**~~

~~(1) In this Code, unless the context otherwise requires,—~~

~~**distributor pricing methodology requirements** means the requirements in Schedule [00]~~

~~**standard contract** has the meaning given to it in the Electricity Distribution Information Disclosure Determination 2012 made under Part 4 of the Commerce Act 1986, as amended from time to time~~

~~**[00.1] Distributor pricing methodology requirements**~~

~~(1) Every **distributor** must comply with the **distributor pricing methodology requirements** in Schedule [00].~~

~~(2) This clause applies despite anything contrary in any agreement or the **regulated terms**.~~

~~**Schedule [00]**~~
~~**Distributor pricing methodology requirements**~~

12A.7~~1~~ Payments for injection

(1) A **distributor's** pricing methodology must~~:~~, for any **price category** that has eligibility criteria that are designed to target residential or small business consumers, include a negative charge for injection of **electricity** into the **distributor's network** that:

(a) applies at times when demand in the region where the **ICPs** in that **price category** are located is likely to, on average and over time, drive future network investment; and

(b) is based on either—

(i) the long-run marginal cost of peak demand that can, on average and over time, be avoided by injection that occurs at the times identified in paragraph (a) from **ICPs** in that **price category**; or

(ii) for the pricing year beginning 1 April 2026, the difference between the peak charge and off-peak charge for consumption of **electricity** for **ICPs** in that **price category**; and

(c) has regard to transaction costs, consumer impacts, uptake incentives and network stability.

~~(a) provide for the identification of any **ICPs** or groups of **ICPs** that are—~~

~~(i) subject to **standard contracts**; and~~

~~(ii) connected to the **distributor's network** at a location or locations where injection can provide **network** benefits; and~~

~~(b) provide for payments to be made to customers in respect of injection from the **ICPs** identified under paragraph (a)—~~

~~(i) at times when the injection provides **network** benefits; and~~

~~(ii) at a level that shares the **network** benefits from the injection with the **distributor's** customers responsible for the injecting **ICPs**; and~~

~~(iii) in a way that accounts for uptake incentives, **network** stability, and practicality of implementation.~~

(2) A payment resulting from subclause (1)~~(b)~~ may be met by way of a credit against any amount owed to the **distributor** by the **distributor's** customer.

(3) A **distributor's** pricing methodology must disclose:

- (a) how any long-run marginal cost in subclause (1)(b)(i)—
  - (i) has been calculated; and
  - (ii) has been converted into a negative charge for injection (including any adjustment to account for the specific characteristics of injection); and
- (b) how any differential between the peak charge and off-peak charge in subclause (1)(b)(ii) has been converted into a negative charge for injection (including any adjustment to account for the specific characteristics of injection); and
- (c) the form of the negative charge and the time periods or circumstances in which it applies; and
- (d) any important assumptions relied upon.

(4) A **distributor** must not use charges from a regulated distributor tariff option (as defined in regulation 4 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004) for the purposes of subclause (1)(b)(ii).

(5) This clause applies—

- (a) to **distributors'** pricing methodologies that apply on and after 1 April 2026; and
- (b) despite anything contrary in any agreement or the **regulated terms**.

~~(3) For the purposes of this clause, injection of **electricity** provides **network** benefits where it avoids, reduces, or defers the costs of required investment in the **network**, relative to the costs of required investment without the injection, as reasonably estimated by the **distributor** at present value.~~