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

Consultation paper

Energy Competition Task Force initiative 2A

12 February 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

When consumers with rooftop solar and other types of small-scale electricity generation supply surplus energy into the electricity network at peak times, this significantly benefits New Zealand's electricity system. The Energy Competition Task Force (Task Force), jointly established by the Electricity Authority Te Mana Hiko (Authority) and the Commerce Commission Te Komihana Tauhokohoko (Commission), believes more needs to be done to unlock these benefits.

The Authority, on behalf of the Task Force, has identified opportunities to do this by:

- requiring distributors to pay a rebate when consumers supply electricity at peak times (Task Force Initiative 2A)
- requiring retailers to fairly reward consumers with power generation systems for the electricity they supply at peak times (Task Force Initiative 2C).

This paper sets out the Authority's proposal under Task Force Initiative 2A to require distributors to pay a rebate when mass-market[1] consumers supply electricity at peak times. When we refer to 'paying rebates to consumers' and distributors 'rewarding consumers' in this paper, we mean that under these proposals any rebate would be incorporated into distributors' charges to retailers. Our proposals under Task Force Initiative 2C[2] would complete the process by ensuring retailers pass this rebate on to consumers through buy-back pricing plans. The Authority is currently consulting on the Initiative 2C proposal alongside the Initiative 2B proposal to require retailers to offer retail pricing plans that reward consumers for using electricity at off-peak times.

Incentivising consumers to supply electricity at peak times helps lower power prices for all of us over the long term. If more consumers supply electricity when demand is highest, for example by selling energy stored in batteries in the evening peak, this will lead to reduced demand on the electricity system. This lowers the lines costs that we all pay for through our power bills.

The Authority recognises it can be difficult for distributors to calculate the value this local generation will contribute to the network. It can therefore be difficult to set pricing plans that fairly reward households, businesses and other consumers with small-scale generation systems for the cost savings they create. But these types of pricing plans are necessary to ensure investment in expensive network infrastructure – and therefore distribution costs – are efficient.

In this consultation paper, we propose requiring distributors to pay rebates when consumers feed electricity into the network in a way that provides network benefits. We would achieve this by requiring distributors to identify groups of consumers whose generation could provide network benefits and offering rebates that comply with a set of mandatory principles. This

[1] In this paper, we use the term 'mass-market' to refer to consumers that are on 'standard contracts' (as defined by the Commission's information disclosure rules). This can include households, small and medium businesses, farms, etc, but usually excludes large industry.

[2] See Improving price plan options for consumers: Time-varying retail pricing for electricity consumption and supply.

would enable distributors to reward generation in a targeted and appropriate way, based on the network's local circumstances and other relevant factors.

We believe this proposal will incentivise more efficient investment in and operation of electricity distribution networks and help reduce peak demand. We note that in the short to medium term, distributors are likely to recover the cost of the rebates by increasing their charges for customers generally. But we expect the short-term financial impact is likely to be very minor and outweighed by the significant long-term benefit of lower power bills for all consumers.

Other options we considered

We also considered other ways to ensure the reward consumers get for supplying electricity at peak times reflects the value they provide to the network. These include:

- Requiring distributors to provide rebates for small-scale (consumer) generators where this benefits the network, but to do so in line with more prescriptive rules rather than a principles-based approach. We consider this option has the advantage of certainty, ie, it would be clear for distributors what kind of rebate they must provide. But it could not realistically be well tailored to the specific circumstances of each network, so would inevitably result in rebates that would not appropriately reward the benefits provided.
- Requiring distributors' pricing for injection from small-scale generators to be linked to their consumption charges. This option also has the advantage of certainty, and some level of symmetry between consumption and supply prices – it makes intuitive sense that the two are linked. However, we consider that as consumption pricing is not sufficiently targeted, this approach could result in rebates that over-incentivise supply where it does not provide network benefits.

This proposal is one of the eight initiatives being considered by the Task Force, established by the Authority and the Commerce Commission in August 2024 to investigate short- and medium-term initiatives to strengthen the electricity market.

Two other Task Force initiatives are being explored as part of this consultation package that similarly aim to provide more options for consumers to manage their electricity use and costs so all consumers can benefit over the long term. We recommend reading this consultation paper alongside our Initiative 2B and Initiative 2C combined consultation paper.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The Electricity Authority Te Mana Hiko (Authority) is considering rewarding consumers[3] who sell energy into the system when and where it benefits their local distribution network by reducing the need for more network infrastructure.

1.2. The consultation paper proposes Code amendments that would place new obligations on distributors. We are now seeking feedback to explore this issue further and test the proposed possible solution.

1.3. This paper is part of Energy Competition Task Force initiative 2A: consider requiring distributors to pay a rebate when consumers export electricity at peak times.

How to make a submission

1.4. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to taskforce@ea.govt.nz with 'Consultation paper — Requiring distributors to pay a rebate when consumers export electricity at peak times' in the subject line.

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

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

(a) indicate which part should not be published and explain why you consider we should not publish that part.

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

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

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

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[3] As noted in the executive summary, we use the terms 'rewarding consumers' and 'paying rebates to consumers' throughout this paper. However, we note that this proposal relates to distribution pricing, so would require distributors to pay these rebates to the consumer's retailer. Another Task Force initiative (as discussed in our 'Improving pricing plan options for consumers' paper) would ensure that retailers pass through this reward to consumers in some form.

When to make a submission

1.9. Please deliver your submission by 5pm, Wednesday 26 March 2025.

1.10. The Authority will seek cross-submissions for a two-week period following the deadline for submissions above.

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

2. Introduction

This consultation package supports Energy Competition Task Force initiatives to provide consumers with more options

2.1. The Electricity Authority Te Mana Hiko and Commerce Commission Te Komihana Tauhokohoko jointly established the Energy Competition Task Force (Task Force) in the context of a period of sustained high wholesale electricity prices in August 2024, driven primarily by fuel shortages. The Task Force was established 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. The Task Force is focusing on short- to medium-term actions to improve the performance of the electricity market.

2.2. The Task Force's work programme focuses on two overarching outcomes:

(a) Package One – enabling new generators and independent retailers to enter, and better compete in the market

(b) Package Two – providing more options for end-users of electricity.

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

2.4. The Task Force is considering both new initiatives and some that are already underway but can be accelerated so New Zealanders can benefit from a better performing electricity system sooner.

2.5. This consultation paper relates to initiative 2A to 'consider requiring distributors to pay a rebate when consumers export electricity at peak times', under the Task Force's intended outcome to 'provide more options for end-users of electricity'. This initiative, in concert with the time-varying pricing initiatives (2B and 2C) being consulted on in parallel, 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

(b) ultimately benefit all consumers by increasing the peak time flexibility options available to distribution networks, which should reduce network (poles and wires) investment over time, as described below.

Flexible distributed generation can help reduce system costs going forward

2.6. New Zealand's electricity system is transforming, creating some key challenges that must be managed:

(a) Electricity demand is projected to grow rapidly in the next couple of decades.

(b) Peak demand – i.e., the point when electricity use is highest – is also growing.

(c) The country's generation mix is changing, with an increasing penetration of variable renewable generation – particularly wind and solar.

2.7. Distribution networks must be able to meet peak demand. Higher peak demand requires additional network investment, which can be expensive and increase electricity costs for consumers. Flexible distributed generation, such as batteries, can reduce net peak demand by injecting into the network at peak times and offsetting consumption from other consumers on that part of the network. When this occurs routinely, it can reduce a distributor's need to invest in additional network capacity as demand on the network grows. This reduces costs for the network, reducing costs for all consumers in the long run. When flexible distributed generation is appropriately rewarded, it also allows consumers to reduce their total energy bills by generating electricity to support the network.

2.8. Flexible distributed generation (DG) also has other benefits. It can:

(a) Be a cheaper source of energy at peak times than large-scale flexible generators such as gas Peaker's. If enough consumers provide flexibility in this way, it can reduce the need to build and operate such generation, bringing electricity prices down.

(b) Improve community energy resilience as more households and businesses increasingly invest in their own generation.

2.9. The benefit of encouraging consumers to increase their investment in and operation of distributed generation where efficient through accurate price signals – and to do so more quickly – was recognised by the Task Force when it was established by the Authority and Commerce Commission in August 2024.

The Task Force initiatives fit with the Authority's strategic priorities and other projects

2.10. Through our work, we continuously seek opportunities to drive value for consumers and promote competitive and efficient mechanisms to enable an electrified future for New Zealand. This requires a future in which investment and innovation flourish; consumers have more control over their electricity; widespread use of technology helps stabilise the grid (such as electric vehicles, battery storage and smart chargers); and communities are increasingly resilient in the face of significant weather events and natural disasters.

2.11. The Authority is working on other regulatory measures to encourage more cost-reflective distribution prices to incentivise activity that reduces the need for additional network investment and therefore reduces costs for all consumers over the long term. In particular, the Distributed Generation Pricing Principles issues paper, which we have released at the same time as this paper, focuses on pricing for larger distributed generators.

2.12. The Authority is also considering other initiatives proposed by the Task Force:

(a) Requiring retailers to offer time-varying retail prices, including for injection. This will better ensure that distribution price signals – as well as other price signals – are passed through to consumers (Task Force initiatives 2B and 2C). This time-varying pricing initiative is particularly relevant to the distribution tariff proposal in this paper as it better ensures that the signal from any distribution rebate gets through to consumers, so they have the option to reduce their energy bills by generating in such a way that benefits the network.[4]

(b) Measures that would enable industrials to be appropriately rewarded for the benefit their flexible electricity use brings to the system (Task Force initiative 2D).

(c) Changes to enable new generators and independent retailers to enter and better compete in the market (Task Force Package One initiatives, 1A, 1B, 1C and 1D).[5]

2.13. Please note, while the 'Improving pricing plan options for consumers' consultation paper primarily addresses retail pricing, it also includes a complementary measure that would require distributors to assign ICPs to time-varying distribution tariffs where these are available. Despite being a distribution pricing matter, it is discussed in that paper as it is relevant to the input costs that retailers face when determining whether to offer time-varying price plans.

4 See our accompanying 'Improving pricing plan options for consumers' consultation paper.

5 See Energy Competition Task Force | Our projects | Electricity Authority.

3. Existing arrangements

3.1. Distribution pricing is set by distributors and charged to distribution customers. Most mass-market[6] consumers will not face these charges directly, as their retailer is most often the distributor's direct customer. The retailer will pay distribution charges on the consumer's behalf and then pass these charges on to consumers, generally repackaged with other costs, such as energy costs, retail overheads and levies.

3.2. The Authority has power to amend the Electricity Industry Participation Code 2010 (Code), where it is consistent with the Authority's statutory objectives, and it is necessary or desirable to promote the matters in section 32(1) of the Electricity Industry Act 2010. This ability to develop Code includes setting pricing methodologies. The Authority encourages distribution pricing to be cost-reflective, so consumers face prices that encourage them to manage their electricity use and generation in such a way that reduces strain on the network, therefore reducing infrastructure costs.

3.3. Consumption pricing is currently regulated differently from DG pricing. The Distribution Pricing Principles (DPPs) (as set out in Box 1 below) contain non-mandatory guidance,and exist outside the Code. Under these principles distributors have flexibility to design efficient, cost-reflective pricing for consumption that reflects local circumstances.

Box 1: Distribution pricing principles

- Prices are to signal the economic costs of service provision, including by:
  - being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);
  - reflecting the impacts of network use on economic costs;
  - reflecting differences in network service provided to (or by) consumers; and
  - encouraging efficient network alternatives.
- Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.
- Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:
  - reflect the economic value of services; and
  - enable price/quality trade-offs.
- Development of prices should be transparent and have regard to transaction costs, consumer impacts and uptake incentives.

[6] As noted in the executive summary, in this paper we use 'mass-market' to refer to consumers that are on standard contracts (as defined by the Commission's information disclosure rules). This can include households, small and medium businesses, farms, etc, but usually excludes large industry.

3.4. For pricing DG, distributors must adhere to the Distributed generation pricing principles (DGPPs), which are mandated in the Code for distributed generators on regulated terms. These principles are more prescriptive about what distributors must or must not do or consider, including a requirement to deduct avoided cost of distribution (ACOD) from a distributed generator's charges.

Box 2: Excerpt from distributed generation pricing principles (clause 2 of Schedule 6.4 of the Code, and clause 1.1(1) of the Code, definition of incremental costs)

Charges to be based on recovery of reasonable costs incurred by distributor as a result of connecting the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs.

… connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the **distributed generation** …

incremental costs, for the purpose of Part 6, means:

(a) the reasonable additional costs (which include any reasonable additional transmission costs) that an efficient **distributor** would incur in providing **electricity** distribution services to **distributed generation**; minus

(b) the distribution costs (which do not include any transmission costs) that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**.

4. Problem definition

4.1. This section outlines:

(a) how existing distribution pricing arrangements do not provide an efficient incentive for mass-market customers with DG to inject at times and locations where this would provide network benefits

(b) why this is an urgent issue to be resolved.

There is a missing distribution price signal for injection

4.2. Many prices for using distribution networks have some component – usually a peak price – that generally signals when consumption is contributing to network costs. The Authority expects this signal will become increasingly prevalent across consumption prices for end users, including in response to the other Authority workstreams.

4.3. Although this pricing is unlikely to be perfectly cost-reflective, it nonetheless incentivises consumers[7] to reduce their own demand (through reducing consumption or using their own generation to offset some of their demand) at times and locations where this benefits the network.

4.4. However, there is generally no distribution incentive for consumers to *inject* into the network (ie, to feed excess electricity back into the network), even when this can also benefit the network by reducing pressure on upstream parts of the network that may face constraints in the future.[8] As noted by Rewiring Aotearoa's 'Symmetrical Export Tariffs' paper, "as soon as a household with solar and battery moves from consuming to exporting, the network tariff vanishes".[9] In addition to being inefficient, this missing price signal lessens the options consumers have to reduce their power bills by generating electricity in ways that benefit the network.

4.5. The DGPPs do not appear to be providing such a signal, particularly for mass-market DG.[10] Orion offers an export credit[11] and Aurora Energy has recently trialled a credit scheme that rewards peak injection from some customers.[12] But the

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7 As noted above, these incentives are on the distribution customer, who tends to be the retailer rather than individual consumers. However, retailers are incentivised to pass through this signal or otherwise incentivise consumers to respond during peak periods. Our proposed measure in the accompanying 'Improving pricing plan options for consumers' consultation paper provides another safeguard that ensures some degree of pass-through to consumers.

8 Consumers are likely to receive some reward from their retailer for exporting to the network, but this will be passing through wholesale market benefits (ie, based on the energy exported) rather than any distribution network benefits.

9 See Rewiring Aotearoa's 'Symmetrical Export Tariffs' paper.

10 ACOD payments for larger DG are also rare – this issue is discussed in the Authority's Distributed Generation Pricing Principles issues paper.

11 See Export credits policy - applicable from 1 April 2024.

12 Customers must be in the Upper Clutha/Wanaka area, have a connected capacity of at least 69kVA, have half-hourly metering, and be capable of exporting during critical peak demand periods. See paragraph 95 of Aurora Energy 'Pricing Methodology', 1 April 2024.

Authority is not aware of any other distributors with pricing that rewards peak injection from mass-market customers for the distribution benefits it can provide.

Challenging to implement

4.6. This may be because it can be challenging to implement these price signals in practice for mass-market consumers, as injection can either reduce or add to network costs depending on the time and location of the injection. For example:

(a) When consumers inject electricity into the network during winter evenings when demand is high, net demand on the network will be reduced. Over time, this may reduce distributors' need to invest in additional network infrastructure to deal with growing demand, therefore avoiding network costs.

(b) When consumers inject electricity into the network during the middle of the day at a location where the network is already export constrained by lots of other solar DG, this may contribute to additional investment requirements.

(c) When DG injects at a time and location where the network has lots of spare capacity for both export and import, the injection is unlikely to incur or reduce any network costs.

4.7. This makes it difficult to determine a standard value of injection that can be incorporated into standard contracts, so most distributors do not offer any standard reward for mass-market consumers injecting electricity back into the network.

4.8. Distributors may reward injection from mass-market consumers if they procure flexibility from an aggregator (see discussion on contracted flexibility from paragraph 5.19). In these cases, the aggregator will likely pay the mass-market consumers (or other parties) in exchange for being able to control their DG. However, this kind of contracted flexibility has been limited so far, so most consumers do not have the opportunity to be rewarded for their injection in this way.

The consequences of not rewarding network injection at peak times

4.9. Customers will generally choose the size of their DG investment in response to price signals; in other words, the size is based on what is most economic for them. Under the status quo, this may not align with what is optimal for the broader system. Essentially, because of this missing distribution price signal, some consumers may install a solar and battery system that can meet their own demand at peak times, but not have spare capacity to inject electricity into the network, even though there could be a benefit to the distribution network of doing so (alongside other potential benefits).

4.10. The potential benefits of fixing this missing price signal are considerable. Boston Consulting Group's 'The Future is Electric' report estimates more than $20 billion will need to be invested in distribution networks *every decade* until 2050.[13] Even if more injection from mass-market consumers only reduced or deferred a small

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[13] See The Future is Electric - A Decarbonisation Roadmap for New Zealand's Electricity Sector.

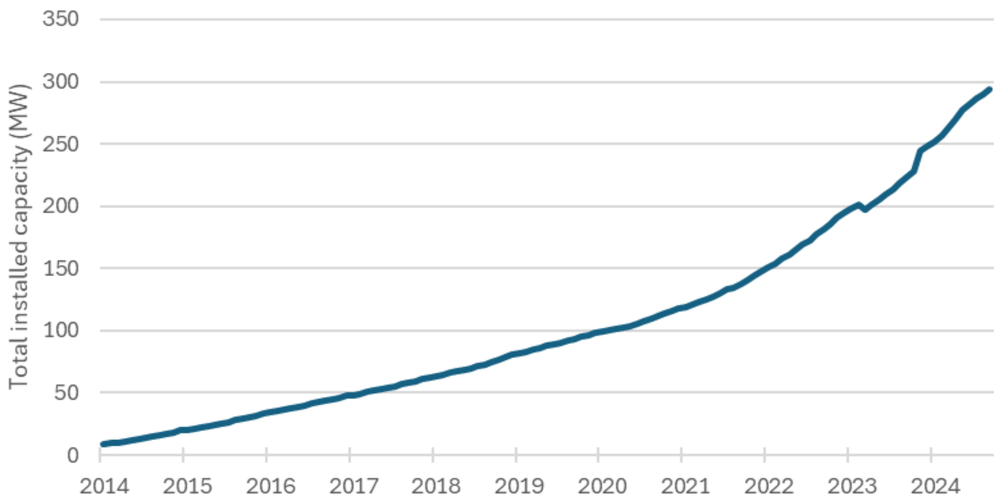
proportion of this investment, it would still result in substantial savings for distributors – and consumers – in the long run.

Why the Authority is addressing these issues now

4.11. Small-scale DG was relatively uncommon when many distributors set up their pricing arrangements. Because electricity on the network flowed almost entirely in one direction, pricing regulation only focused on encouraging reduced *consumption* during peak times.

4.12. However, with improvements in solar and battery technologies, lower costs, and more installation and financing options, there has been a large rise in small-scale DG, which is likely to continue (see Figure 1). This rise in two-way electricity flows gives distributors more opportunities to encourage mass-market customers to *inject* during peak times also, as a way to relieve upstream constraints and save on network costs.

Figure 1: Small-scale (<10kW) distributed solar capacity in New Zealand[14]



4.13. While this paper primarily focuses on how this problem affects distribution networks, more investment in DG can provide wholesale market benefits by reducing the requirement for more expensive generation. The period of high wholesale prices in August 2024, due to gas shortages and low lake levels reducing the amount of flexible generation available, highlighted the importance to the wholesale market of other sources of flexible generation. This was recognised by the Task Force when it developed its work programme, including its Package Two initiatives.

Q1. Do you agree with the problem definition above? Why, why not?

[14] Note there was a categorisation issue during 2023 where some solar and battery systems were categorised as ‘other’, rather than ‘solar’. See the ‘More information’ tab at Electricity Authority - EMI (market statistics and tools) for details.

5. Proposed solution and alternative options

5.1. This section outlines the Authority's proposed solution to the problem described above, and discusses the key issues and design questions considered when developing this solution. This section also describes other solutions considered by the Authority that are not preferred, but that we would welcome stakeholder feedback on.

Proposed solution: principles-based rebates[15]

5.2. The Authority's preferred solution is to require distributors to reward injection from mass-market consumers in circumstances where it benefits the network, in accordance with principles incorporated into the Code. A principles-based approach would give distributors flexibility to make payments for injection in ways that best suit their network, taking into account individual network circumstances. The payments would likely be appropriately targeted, which reduces the prospect of unintended and inefficient subsidies – ie, payments for injection, ultimately funded by other consumers, where it provides little or no network benefit. By mandating these principles as a Code requirement, the Authority could enforce compliance, which should result in a stronger and more urgent response from distributors.

5.3. These principles are outlined at Box 3 below, and the full proposed Code amendment is included in Appendix B.

Box 3: Proposed principles for pricing injection from mass-market consumers

A distributor's pricing methodology must:

(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.

Q2. Do you agree with these principles? Why, why not?

15 We use the term 'rebate' because it is likely distributors would not make net payments to a distribution customer (ie, a retailer), but rather reduce charges for that customer.

Scope

5.4. As discussed above, the lack of distribution price signals for injection is most prevalent for mass-market consumers, because the value of injection to the network varies depending on time and location, making it difficult to reward injection on a standardised basis. As such, these proposed principles would apply only to mass-market consumers. This would be reflected in the Code by only requiring distributors to apply these principles to customers on 'standard contracts'. A standard contact is defined in the Commerce Commission's Information Disclosure Determination as:

> *any contract … between an EDB and any other person where: (a) the price … is determined solely by reference to a schedule of prescribed terms and conditions, being a schedule that is publicly disclosed; and (b) at least 4 other persons have such contracts with the EDB.*

5.5. We considered requiring distributors to apply the proposed principles to customers on non-standard contracts – ie, requiring distributors to also pay rebates to larger consumers or generators. However, because it is easier for distributors to determine the value of injection from a larger individual customer on a bespoke contract, the Authority considers that no specific urgent reform is required for non-standard customers. Instead, any requirements for injection pricing for customers on non-standard contracts should be developed in line with other reform to the Distributed generation pricing principles, as discussed in the accompanying issues paper.

5.6. The principles would apply to consumers on standard contracts with any DG that can inject into the network. This may include inflexible DG, such as solar without batteries. In most cases, such generation is unlikely to inject at times that benefit the network (for example, because of the way peak demand does not correlate with times when solar generation peaks), so distributors would not be required to reward such injection. However, there may be other circumstances where inflexible solar generation correlates with periods of peak demand, for example where distribution networks have large irrigation loads in summer. In these cases, inflexible solar DG may provide network benefits and should be rewarded.

Q3. Do you agree that the principles should only apply to mass-market consumers, or should they apply to larger consumers and generators also? Why, why not?

Q4. Do you agree the principles should apply to all mass-market DG, including inflexible generation (noting that the amount of rebate provided will still be based on the benefit the DG provides)?

Additional guidance

5.7. As noted above, a principles-based approach provides distributors with flexibility to reward injection in a way that reflects their network circumstances. The proposed principles themselves set out high-level factors that should be taken into account when determining the times any rebate should apply and the level at which it should be set. The Authority would publish additional guidance (outside the Code) on how these factors should be considered in practice. We expect this guidance could include the following indicative points (but would seek feedback from stakeholders on any draft guidance documents).

(a) Distributors would be required to identify where consumers' injection can provide network benefits by reducing peak demand and therefore helping avoid or defer future network investment. The Authority expects that distributors could identify these consumers based on where they have forecast network constraints in their asset management plans.

(b) The principles would require distributors to reward injection that occurs at times that it provides network benefits. Specifically, this will be at times when demand is being used to forecast future peak demand growth, which is then used to inform investment plans, noting that different distributors may use different time horizons, risk tolerances and other assumptions. As a starting point, distributors should therefore offer rebates at times where injection will affect future demand forecasts – for example, if peak demand in summer is never high enough to drive future investment, rebates should not be offered in summer. However, the Authority accepts that spreading this rebate across a broader and more stable time period may be appropriate to take into account other factors, such as uptake incentives (see discussion at (e) below).

(c) Distributors should set rebate levels based on the amount of network benefits the injection provides. For example, where injection occurs on a part of the network that is likely to face constraints in the next few years, it should be rewarded more than injection that occurs where constraints are only likely later in the future, as the former will result in a higher present value of avoided network costs.

(d) Where injection results in network benefits, distributors would have to share this value with the customers responsible for the injection (ie, retailers, who would then pass this value through to the relevant consumers). However, this does not mean distributors should pay 100% of these network cost savings as rebates. To do so would not result in any network cost savings that can be passed through to consumers in general through lower overall network charges. Distributors should therefore pay rebates at a rate that is high enough to incentivise injection, but not so high that there are no cost savings for the wider consumer base.

(e) Consumers may be more likely to invest in DG[16] if the distribution price signal they receive is more stable. In reality, a consumer's injection may only truly benefit the network a few times a year when it coincides with a new network peak and therefore influences future peak demand forecasts. Furthermore, if and when the network does invest in additional capacity, this injection may no

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16 In practice, this will mostly affect investment in batteries (often together with rooftop solar), which are expected to be the main technology used by consumers to inject into the network at times that benefit the network. However, solar generation without batteries may also sometimes provide network benefits (eg, if it is angled in such a way that maximises its generation in the morning and early evening, or if the network is most likely to be demand constrained during the middle of the day, such as where there is significant irrigation load). Other technologies such as diesel generators may also provide opportunities for consumers to take advantage of these rebates.

longer provide any benefits at all. As such, a perfectly cost-reflective rebate may be high, but rare and short-lived. Distributors may instead choose 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.

(f) Once there is sufficient DG on the network that is taking advantage of the rebate and injecting at beneficial times, forecast peak demand growth may become fairly limited. This means that value of additional injection into the network may be lower. As such, distributors could provide no rebate for new injection and maintain rebate levels for existing DG. This would maintain the stability of the price signal for this existing DG, but would create some first mover advantage. Alternatively, distributors could lower the value of the rebate for all customers, which would result in more equitable, but less certain rebates.

(g) Distributors may want to consider how feasible it will be for retailers to pass through complex price signals to consumers.[17] For example, some retailers may not want to pass through extremely granular price signals, so a more appropriate staring point may be to provide rebates through specific tariff codes to larger groups of ICPs that can help relieve constraints in the high voltage network. More granular distribution rebates could follow in the future to address constraints in the low voltage network if distributors consider retailers are likely to pass through such signals, but until then, contracted flexibility may be a more appropriate option (see discussion at 5.19 below).

(h) Too much injection into the network when demand is low can risk causing export congestion or voltage issues, which could lead to additional network costs. In such situations, the injection is not providing network benefits, so under the principles it should not be rewarded. However, due to other considerations noted in the principles – ie, uptake incentives and practicality concerns – distributors may nonetheless offer rebates at times that do create some risk of over-incentivising injection. Distributors can address this risk by using network standards to limit the amount of injection into the network, but we consider that there is a level of injection where distributors should be able to stop incentivising injection (ie, not provide a rebate), before prohibiting further injection altogether. As such, distributors should be allowed to cap rebates for injection above a certain capacity.[18]

Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?

Q6. Are there any additional issues with the principles where guidance would be particularly helpful?

17 See the 'Improving pricing plan options for consumers' paper

18 Distributors should also consider *charging* DG for injection at times and locations that *increases* future network investment costs, ie, where there is a large amount of solar generation without batteries, combined with low demand, leading to a high export in the middle of the day.

Compliance, monitoring and enforcement

5.8. Unlike the distribution pricing principles, the proposed principles would be incorporated into the Code so distributors would be required to comply with them when setting their pricing methodologies. These pricing methodologies are required under the Commerce Act regime to be published, which enables the Authority to review them and determine whether or not they are compliant.

5.9. The Authority would have flexibility around how it reviews pricing methodologies and monitors compliance with these principles. It would not necessarily have to undertake an in-depth review of all distributors' methodologies. Rather, it may choose to target its efforts towards distributors it considers may be lagging in this area – possibly based off previous assessments or feedback from the wider industry.

5.10. If the Authority determined that one or more distributors' pricing methodologies did not comply with these codified principles, it could in the first instance encourage and assist those distributors to amend their pricing methodologies so that they become compliant. If the distributors were unable or unwilling to amend their pricing methodologies in this way, the Authority could:

(a) set a prescriptive pricing methodology for non-complying distributors or specific groups of distributors (under its power under section 32(4)(b) of the Electricity Industry Act) that is compliant with the principles

(b) take enforcement action against non-compliance through the standard Code breach process (which could include financial penalties for the distributor).

Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?

Timing

5.11. We are proposing that the Code amendment would come into effect on 1 April 2026 to align with the start of the 2026–2027 pricing year for distributors. As such, their pricing methodologies for that year would need to be compliant with these principles.

5.12. This proposed timeframe balances the urgent need to provide consumers with more options to manage their energy bills so benefits can be more quickly realised, with the need to provide time for distributors to implement the change. We expect this proposal would require distributors to undertake some work to identify future constraints on their network that injection from DG could help alleviate, and calculate appropriate rebate levels. The Default Distributor Agreement (DDA) also includes terms that limit price changes to once a year. We also acknowledge distributors have to comply with the Commission's Information Disclosure rules which mandate certain times and processes around changes to pricing methodologies. While these rules do not prohibit distributors from changing prices mid-year, they reinforce our rationale that this timing is sensible given expected consultation timeframes between distributors and retailers.

Q8. Do you agree with the proposed implementation timeline for this proposal? If not, please set out your preferred timeline and explain why that is preferable.

Relationship with existing regulation

5.13. As discussed above, the existing DGPPs require distributors to charge distributed generators only the incremental cost of that DG being connected to the network, taking into account the avoided cost of distribution (ACOD). This proposal helps ensure distributors give effect to these requirements for mass-market consumers who are also distributed generators, by reducing their charges relative to what they would pay if they did not also benefit the network by generating at peak times.

5.14. However, there are several issues with the DGPPs and the Authority considers they may no longer be fit for purpose. The 'Distributed generation pricing principles' issues paper therefore proposes a comprehensive overhaul of the DGPPs. In practice, this could involve extending the distribution pricing principles so they also apply to distributed generation, or through incorporating similar principles into the Code, potentially alongside the Code amendment proposed in this paper.

5.15. Either way, the Authority considers reform of the DGPPs is needed to address slightly different issues to this proposal. In particular:

(a) overhauling the DGPPs would allow distributors to charge DG *more than avoidable costs* (ie, including a contribution towards common costs), provided these charges remained within the subsidy-free range

(b) this proposal would require distributors to charge mass-market DG *less than it would have been charged if it did not inject* in ways that benefit the network (ie, providing a rebate).

Relationship with consumption pricing

5.16. Unlike the alternative option the Authority considers from paragraph 5.34, its preferred approach would allow pricing for DG to be set independently from consumption pricing. Distributors would continue to have flexibility to decide how they set prices for consumption, guided by the existing distribution pricing principles.

Australia takes a principles-based approach

5.17. Australia also takes a principles-based approach to injection rebates, as noted in Box 4 below.

Box 4: Export (injection) tariffs – the Australian approach

In August 2021, the Australian Energy Market Commission (AEMC) updated the regulatory framework to integrate distributed energy resources (DER) such as small-scale solar and batteries more efficiently into the electricity grid.[19] The new rules contain

19 Australian Energy Market Commission. 2021. Rule Determination- National Electricity Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021.

obligations on distributors to support more DER connections to the network. As part of its decision, the AEMC removed the prohibition on distribution businesses from developing export pricing options and allowed networks to propose the introduction of export tariffs to the Australian Energy Regulator (AER).

In May 2022, the AER published the Export Tariff Guidelines.[20] An export tariff, according to the AER, is one that includes a charging component for exporting energy into the grid). It can include:

- a **positive charging** component, or a cost for exporting customers, to indicate when exported energy would drive future network investment
- a **negative charging** component, or rebate for exporting customers, when the network would benefit from exports, and customers can be rewarded for exporting.

AER provides the following example of two-way-pricing that incorporates both positive and negative charges to exporting (injecting) consumers:

Residential two-way tariff	Time period	Charge per unit	Price per unit (cents)
Fixed charge	Daily	c/day	50.0
Peak consumption charge	4 pm – 9 pm	c/kWh	20.0
Shoulder consumption charge	9 pm – 10 am	c/kWh	5.0
Off-peak consumption charge (solar sponge)	10 am – 4 pm	c/kWh	1.5
Export peak rebate	4 pm – 9 pm	c/kWh	20.0
Export charge* applies to exports > 2 kWh/day (that is, the basic export level is 2 kWh/day).	10 am – 4 pm	c/kWh	1.5

The current approach of the Australian regulator (through guidelines) is characterised by the following:

- The guidelines are non-binding and are intended to be principles-based rather than prescriptive to allow for differences between distributors.
- They offer information and instructions to distributors and other stakeholders on how networks should explain future proposals for export tariffs and define the rates.
- The AER will not approve export pricing proposals unless a distributor can, through the regulatory proposal process, demonstrate its need.

When proposing export tariffs, distributors need to consider the individual circumstances of their network, the potential impacts on customers if export tariffs are not introduced, and the current or estimated future DER penetration on the network. An essential aspect of justifying the need for two-way pricing is engaging with stakeholders.

The AER emphasises that export tariffs have several benefits, such as promoting efficient network use and enabling fair cost recovery. Additionally, implementing export charges and providing rewards for exports where appropriate and during specific times can foster the adoption of new technologies, services, and business models, thereby delivering a wide array of benefits to customers, networks, and the environment.

20 See AER - Export Tariff Guidelines - May 2022.

5.18. However, unlike the Australian regime, the principles in the Authority's proposal are not voluntary. We consider voluntary principles would provide distributors with too much flexibility in respect of mass-market customers. Unlike in Australia, where pricing proposals must be approved by the regulator, New Zealand distributors might choose not to comply with voluntary principles and guidance, and could fail to offer any cost-reflective rebates to small-scale DG on the basis that it is too difficult to work out how much value (if any) it provides to the network. While the Authority would continue to monitor outcomes and would have the option of moving to a more prescriptive approach, we do not consider this option would result in a sufficiently urgent response. We have observed slow progress from some distributors in response to the Distribution pricing principles, and the same could occur here. Distributors may prefer to undertake rigorous analysis to determine precisely where and when injection from any DG (including small-scale DG from mass-market customers) will be deferring network investment, despite being comfortable progressing mass-market consumption pricing using more general and imprecise methodologies.

Relationship with contracted flexibility and aggregators

5.19. FlexForum's 'Flex Plan 1.0' notes consumers can provide flexibility in two ways: price-based flexibility and contracted flexibility.[21]

(a) Price-based flexibility involves distributors setting tariffs with price signals that incentivise a response during peak times. Distribution customers (usually retailers) will face these signals, as they are the party recorded in the registry as being responsible for the consumer's ICP. Retailers are incentivised to pass these price signals on to consumers or otherwise encourage consumers to respond during these peaks.

(b) Contracted flexibility involves distributors contracting for a particular flexibility response directly from a party that controls a flexibility resource. This is usually an aggregator of some kind that can coordinate a response from a range of resources and therefore provide a larger and more reliable response. In exchange for control over a consumer's flexibility resource, aggregators are likely to provide some kind of reward to consumers.

5.20. This proposal essentially requires price-based flexibility (albeit in only limited circumstances), as it does not require a specific flexibility response – any injection at the specified time and location will be rewarded. As such, rebates would be paid to the distribution customer, which for residential ICPs is their retailer.

5.21. However, we consider there would still be a significant role for aggregators, due to the control and coordination they can provide. Aggregators could still be engaged by distributors to provide contracted flexibility as an alternative to price-based flexibility. The Authority considers that where a distributor has procured (or is planning to procure) flexibility by contracting with an aggregator or other parties to address an upcoming network constraint, the additional benefit from further injection

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21 See FlexForum Flexibility Plan 1.0.

from other DG may be limited. Depending on the extent to which the contracted flexibility reduces the value of additional injection, it may be appropriate for the distributor to provide no additional distribution pricing signal in such cases on the basis that injection does not provide network benefits. We expect to address such issues in the accompanying guidance.

5.22. Aggregators could also be engaged by retailers, or consumers if price signals are passed through, to control their flexibility resources to optimise total benefits from injection rebates and other value streams such as the wholesale market and ancillary services.

Q9. Do you agree the proposal strikes the right balance between encouraging price-based flexibility and contracted flexibility? Why, why not?

Will the proposal (preferred option or alternatives) lead to unfair wealth transfers?

5.23. Requiring distributors to reward mass-market consumers for their injection would reduce the net revenue recovered by distributors. To recover their maximum allowable revenue (MAR) as set by the Commission, distributors are likely to increase their charges that apply to all customers. If passed through by retailers, this would increase bills for consumers who do not have the ability to generate at peak times, which would include households that cannot afford solar and battery systems. This has potential implications for the durability of the proposals if the wealth transfer between consumer groups is considered unfair.[22]

5.24. Quantifying the degree of wealth transfer under a principles-based approach is extremely difficult. It will depend on two key factors, which will vary significantly between distributors and over time, namely:

(a) the total amount of rebates distributors pay, which in turn depends on the number of consumers eligible for any such rebate, consumer uptake rates and rebate levels

(b) how distributors recover this amount from their wider customer base, which in turn depends on how they allocate this shortfall in revenue between consumer groups and how many customers they have on the network.

5.25. However, we can estimate this wealth transfer effect (in the short term) by using consumption-linked injection rebates (an alternative option discussed below) as a proxy for the amount of rebates that would be paid under our preferred option, as the application and level of the rebate under that option is much easier to determine. As discussed in Appendix A, we expect the short-term negative impacts of a consumption-linked rebate on consumers without DG would likely be very small. Because a principles-based approach is more targeted, it is likely that while individual rebates may be higher, fewer rebates would be paid. As such, we expect a principles-based approach would result in the total amount paid by distributors

22 We note that existing consumption pricing already results in similar wealth transfers. When a consumer with flexible load shifts their consumption from peak to off-peak, they pay a lower distribution charge, and the amount by which the charge is reduced must be recovered from other consumers in the short term. We do not consider this has led to durability issues in time-of-use consumption pricing.

(and therefore the wealth transfer implications) to be similar to or lower than a consumption-linked approach in the short term – ie, very small. In the longer term, while the amount of rebate paid may increase, this is likely to be more than offset by a decrease in network investment requirements, leading to lower costs for all consumers.

Q10. Do you agree the proposal will lead to relatively minor wealth transfers in the short term, and will lead to cost savings for all consumers in the longer term?

Alternative option: prescribed rebates

5.26. The Authority considered a similar option that would also require distributors to provide a rebate for injection that provides network benefits by offsetting peak demand and therefore helping avoid or defer future network investment. Unlike the preferred solution, which uses principles to guide rebates, this option would be more prescriptive in terms of when, where and how these rebates would apply.

5.27. This would provide more certainty that distributors would appropriately reward consumers for their injection, as they would have to apply rebates in accordance with a set methodology. By setting this methodology, the Authority would be able to determine certain key elements of the rebate that distributors might otherwise determine differently – potentially less efficiently – due to their incentives or capabilities. It would also provide clearer instructions to distributors as to how the Authority expects them to implement these rebates.

5.28. The two most important elements of the prescribed rebates would be:

(a) The rebate would be provided for any injection that helps relieve a demand-driven constraint that is expected to bind within a set period of time (eg, within the next five years). This would ensure that rebates would be available for all injection that can provide network benefits.

(b) The rebate rate would be set to reflect the long-run marginal cost (LRMC) of the avoided or deferred network investment (or a specified percentage of it). This would ensure that distributors offer a rebate that rewards consumers for the full (or appropriate) benefits their injection provides.

5.29. The general principles behind this option are very similar to the proposed principles-based approach. The only material difference is the degree of flexibility distributors are given as to exactly where, when and how rebates should be provided. The two options exist on a spectrum – if the proposed principles-based approach were made more detailed, it may look similar to if this prescribed rebate option were adjusted to give distributors more discretion.

The Authority would need to engage in further policy development for this option

5.30. This more prescriptive approach would require the Authority to choose particular design parameters, which would require further detailed policy analysis that has not been completed at this stage (as it is not our preferred option). For example, the Authority would need to:

(a) Clearly define when an injection rebate would be required. This would involve determining what would constitute a ‘demand-driven constraint’ (ie, the level of congestion, the time at which it is likely to bind, and the degree of forecast certainty required).

(b) Determine how long the rebate should be offered for to provide a stable investment signal, but without delinking the rebate from network costs or creating perverse incentives for networks to inefficiently delay investment. Too short a signal may not provide sufficient investment certainty for consumers, while too long a signal would result in distributors paying rebates even when they are no longer providing any network benefits (resulting in unnecessary costs for consumers that don't have DG).

(c) Decide whether to specify a particular method that must be used to calculate the LRMC of the avoided/deferred investment, and if so, which one.

(d) Specify whether the rebate would have to be set at the full value of the LRMC, or just a proportion of it (in which case, the Authority would have to also decide on some kind of adjustment factor).

(e) Determine whether the option should include exceptions where distributors have contracted with aggregators for flexibility solutions.

(f) Determine whether distributors should be able to cap the amount of rebates they pay, and any conditions around this – for example, capping rebates on injection above a certain capacity.

5.31. There would also be a risk that the Authority prescribes requirements that are impractical, inefficient, or hampered by information asymmetries. Specified rebates would inevitably result in some circumstances where the rebate does not appropriately reward injection for the benefit it provides, as they would not be tailored to individual circumstances. Trying to account for every possible scenario is not feasible, and could result in complex exemptions that can have other unhelpful consequences.

5.32. We therefore consider it would be preferable to allow distributors some discretion in implementing these rebates to accommodate their particular local situations, as this should result in more accurate and efficient rebates, which in turn are more likely to contribute to efficient investment in DG by mass-market consumers. As such, our preferred option is a principles-based approach.

5.33. However, the Authority is open-minded and would be willing to shift to this option (or another alternative option) based on its consideration of submissions (noting further engagement on detailed parameters and technical consultation would likely be required if a more prescriptive approach was favoured).

Q11. Do you agree that more prescriptive requirements to provide rebates will be less workable than a principles-based approach, and therefore should not be preferred? Why, why not?

Alternative option: consumption-linked injection tariffs

5.34. The Authority also considered requiring distributors to pay rebates for injection during peak demand periods, at a rate based on the distributor's peak consumption rates. Essentially, this means distributors would apply similar pricing to both consumption and injection during peak times.

5.35. This option is similar to Rewiring Aotearoa's Symmetrical Export Tariff proposal outlined in Box 5 below.

Box 5: Rewiring Aotearoa: mandatory symmetrical export tariffs

Rewiring Aotearoa considers the electricity market "was designed for a one-way flow of electricity and does not fairly or cost-reflectively reward services to the system provided by households and businesses – which are now becoming infrastructure". It recommends implementing two-way tariffs quickly to reduce unnecessary infrastructure costs.

It considers:

> "… if a consumer exports electricity, they are only rewarded with an approximation of the wholesale price … the vast majority of networks do not pay for export during peak times, so the payment to the consumer is reflective of the wholesale price only (i.e the value of generation) and not any of the value of network peak reduction."

Rewiring Aotearoa submitted that the Authority should:

> "... not only require TOU consumption tariffs, but also peak-targeted export tariffs for batteries. As far as we are aware, EDBs do not reward peak-aligned export, even though the impact of the marginal kW is identical between the last unit of import reduction, and the first kW of export."

This means that "the network price charged for peak consumption [should] be equally paid to customers if they export at peak times".

Rewiring Aotearoa explains this as:

> "… reducing your neighbours peak load should be treated economically the same as reducing your own peak load. Today, reducing your neighbours peak load is treated as zero value to the network - even though this is demonstrably false. Yet if the neighbour reduces their peak on their own, the value will be provided to them. This is especially apparent with business/farm batteries - which can reduce peak loads of 20 homes or more, and today have no incentive to do so and can sit idle."

The logic of this idea is that an additional incentive is needed to encourage investment in household battery storage, which can lead to cost-effective reductions in the cost of new network assets that would otherwise be needed to meet peak demand growth. Significant peak demand growth is likely in coming years, so the absence of appropriate incentives may be a material problem.

Rewiring Aotearoa also said:

> "…If peak export pricing fairly reflects value provided to the network by that export – ie reflective of the cost of expanding the network – then if a battery can provide this service at lower cost, the battery should 'win' over the network build (that is how level playing field competition is meant to work). As a result, New Zealand homes and businesses can be confident that the lowest cost combination of batteries and new poles and wires will occur."

5.36. However, the alternative option the Authority considered is different from Rewiring Aotearoa's proposal, as the Authority does not consider injection prices should be fully symmetrical with consumption prices for the reasons set out below.

How much should injection pricing mirror consumption pricing?

5.37. There are several factors that justify peak consumption charges and the peak injection rebates being set differently.

5.38. The rationale for linking injection pricing to consumption pricing assumes that consumption charges are generally cost-reflective, and therefore injection rebates will be as well. However, consumption pricing may not be cost-reflective for several reasons.

(a) Pricing reform has not been a priority for some distributors. As noted in the scorecards the Authority uses to assess and evaluate distributors' pricing plans, some distributors have lagged behind the sector and have less efficient pricing.[23] While all distributors have been encouraged to improve their tariffs,[24] the Authority has some reservations about requiring them to offer similarly un-cost-reflective injection rates before they can do so.

(b) The true cost of consumption varies by time and location, so perfectly cost-reflective pricing will be unfeasible in practice, particularly for standardised prices for mass-market consumers. Instead, a trade-off must be made between accuracy and simplicity.[25] While the same trade-off applies to injection pricing, it may be appropriate for injection pricing to sit at a different point on this spectrum (ie, more accurate and less simple, or vice versa) as discussed in the following point.

5.39. The characteristics of DG mean that, in some cases, distributors should reward generation more accurately and less simply than they reward demand response.

(a) Too much injection at any single time or location may impose additional network costs. 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. On the other hand, if demand response is over-incentivised, it may stop providing network benefits, but it will not cause any additional costs.

(b) DG is likely to be more responsive to price. Consumption price signals provide a nudge towards beneficial investment and behavioural decisions, but consumption is still largely influenced by habit and necessity. On the other hand, batteries can be programmed to respond to precise signals. More targeted injection price signals are therefore more likely to be passed through by retailers and acted on by consumers. Likewise, poorly targeted price

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23 See Distribution pricing scorecards 2023.

24 See Open letter to distributors.

25 The Authority considers distribution pricing should have some degree of pragmatism, as reflected in the distribution pricing principle that "development of prices should … have regard to transaction costs, consumer impacts and uptake incentives".

signals are more likely to result in 'herding' behaviours that result in excessive injection, and therefore export congestion or voltage problems.

5.40. For these reasons, mandating consumption-linked injection prices is not the Authority's preferred option. In our view this approach is not targeted or accurate enough, and would likely lead to rebates for injection by mass-market consumers that in many cases were not related to network benefits, essentially providing an inefficient subsidy for that injection.

Suggested safeguards

5.41. However, if the Authority did proceed with this option, it would not be designed to require perfectly symmetrical export tariffs. Instead, it would set a minimum rebate rate that is lower than a distributor's consumption charge rate. Together with other safeguards, this lower minimum rate would reduce the risk of over-incentivising injection when and where it provides limited network benefit, while giving distributors flexibility to offer higher rebates when and where the consumption-linked rate would under-incentivise injection.

5.42. These safeguards would include:

(a) Linking the injection rebate rate to the variable charge *differential* (ie, the difference between peak and off-peak charges), rather than the peak charge in its entirety. This would reflect the component of a distributor's consumption charge that signals periods of peak demand. In theory, cost-reflective consumption pricing should have an off-peak charge of zero (at which point the peak charge and the charge differential would be the same), but some distributors have not implemented such pricing yet.

(b) Applying an adjustment factor that de-rates the minimum injection rebate rate by 50%. We consider such an adjustment would appropriately reflect that demand response and generation should generally be treated similarly, whilst acknowledging their underlying differences. We note that the credit scheme trialled by Aurora last winter effectively used a 50% adjustment factor, and that some Australian distributors use a similar figure (noting that the effective adjustment factor used in Australia can vary substantially between distributors).[26] The Authority would monitor and review distributor progress to ensure that 50% remained an appropriate adjustment factor.

(c) Not requiring rebates for injection above a certain capacity. Distributors can already reduce the risk of export congestion by prohibiting injection above a certain level,[27] but the Authority considers they should be able to stop incentivising injection at a point before they reach the threshold where they need to start constraining injection. The Authority would likely propose that distributors should be able to set the level of injection above which they do not need to provide a rebate, as the risk of export congestion will differ from one

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26 For example, Ausgrid uses an effective adjustment factor of 9%, South Australia Power Networks 38%, Endeavour Energy either 25% or 53% (depending on season), and Endeavour Energy 73%.

27 For example, the Authority understands Orion limits injection on its network from residential DG to 5kW per phase. See Orion connecting your home generation October 2023.

network to another. This level should be based on how much injection the network could handle on average from each ICP without causing additional costs.

(d) Allowing distributors to offer rebates in a more targeted way than the equivalent consumption charge, by:

   (i) offering the rebate for a shorter period than the consumption peak period, provided they offer a proportionally higher rebate during this period

   (ii) offering a rebate that is lower than the mandated minimum in some parts of the network, provided they offer a proportionally higher rebate for other parts of the network

Q12. Do you agree that a consumption-linked injection tariff would not be sufficiently targeted, and therefore should not be preferred? Why, why not?

Q13. If this approach was progressed, do you think:

a) injection rebates should perfectly mirror consumption charges?

b) there are sufficient safeguards in place that would allow distributors to avoid over-incentivising injection to the extent that it incurs additional network costs?

6. Regulatory statement for the proposed amendment

6.1. This section provides a regulatory statement for the proposed amendment.

Objectives of the proposed amendment

6.2. The key objective of the Authority's proposed amendment is to ensure distribution pricing for mass-market consumers with DG appropriately incentivises investment in and operation of DG when and where it provides network benefits by avoiding or deferring network costs.

6.3. This key objective aligns with the Authority's main statutory objective: to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers. The objective also aligns with the Authority's additional statutory objective: the protection of the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers.

Q14. Do you agree with the objective of the proposed amendment? If not, why not?

The proposed amendment

6.4. We propose requiring distributors to reward injection from mass-market consumers in circumstances where it benefits the network, in accordance with principles that will be mandated in the Code.

6.5. Specifically, the amendment will require distributors to:

(a) identify ICPs or groups of ICPs on standard contracts that will provide network benefits if they inject

(b) provide for payments to be made to customers in respect of injection from these ICPs at times which benefit the network, at a level that shares these benefits with these customers

(c) consider uptake incentives, network stability and implementation practicality.

6.6. The drafting of the proposed amendment is contained in Appendix A.

The benefits are expected to outweigh the costs

Competition benefits

6.7. We expect that this amendment will allow distribution pricing for mass-market DG to be on more of a level playing field with:

(a) demand response from mass-market customers, which is already rewarded (in terms of distribution pricing) for the network benefits it provides

(b) larger-scale, non-mass-market DG, which is more likely to be rewarded for its distribution benefits through more bespoke pricing arrangements.

Efficiency benefits

6.8. Relative to the status quo, this proposal promotes efficiency through better signalling the benefits of injection at peak times to parties that can act on those signals. Specifically:

(a) It will improve the extent to which this signal is received by retailers, who can then ensure these signals are passed through to consumers (or aggregators acting on their behalf) in an effective way.

(b) In concert with the proposals in the Authority's time-varying pricing consultation, it will likely improve the extent to which this distribution price signal is received by consumers, who can then make better decisions about their injection, and associated investments.

6.9. We expect better signalling to incentivise injection from mass-market DG when and where this provides network benefits, reducing net peak demand and avoiding investments in more expensive traditional network solutions (ie, poles and wires) in the long term.

6.10. While the additional incentive to invest in batteries as a result of this proposal may possibly be small (depending on the size of the benefits it provides), this signal may be important to consumers whose investment decision is marginal. It is also important to note that any rebate would only form part of the value a consumer may receive from a battery investment (they may also benefit from offsetting their own demand when power is more expensive, as well as improved resilience as discussed in the next section). As such, the rebate does not have to provide the sole investment incentive, but it could play an important role in the wider value stack.

6.11. The proposed amendment may have other efficiency benefits, including reducing wholesale prices from higher levels of peak injection from DG, requiring less generation from more expensive sources.

Reliability benefits

6.12. This measure will have reliability benefits as it will incentivise consumers to make decisions that help to minimise peak demand – including both behavioural decisions, and investment decisions. There is a higher risk of shortage when supply is scarce and networks may be constrained. A consumer's decision to inject at periods of peak demand in response to price signals could help to reduce this risk.

6.13. Further, this measure will have minor reliability benefits as it may incentivise consumers to invest in flexible DG such as batteries where they would not have done so otherwise. These can help avoid wholesale and distribution costs as discussed above, but they can also provide additional resilience benefits to consumers. For example, in the case of a blackout, batteries can provide the consumer with electricity (depending on the battery capacity and charge state) while power is being restored.

Costs

6.14. The Authority expects the implementation costs of the proposal to be relatively minor. Distributors would face costs in setting up systems to implement the proposal, such as ensuring they have sufficient visibility over the network and establishing new tariffs that include an injection rebate. They will also face some additional costs in the preparation of their pricing methodology and any supplementary documentation that can be used to report compliance to the Authority. However, the Authority understands some of these costs are likely to be incurred anyway as distributors move towards more granular and cost reflective tariffs – to this extent, the proposal would largely just be bringing these costs forward in time.

6.15. We recognise a potential risk to any proposal to incentivise injection is the risk of over-incentivising injection, causing export congestion and additional network costs. However, we consider this risk is lower for our proposed amendment, compared with some of the other options we considered (in particular, consumption-linked injection tariffs). That's because our proposal is a principles-based approach that allows distributors to consider their particular local circumstances when incentivising injection.

6.16. Another potential risk is that the effort to implement our proposal means distributors shift resources in the sector away from further reform in consumption pricing. However, we consider our proposal could actually lead to more efficient further reform in consumption pricing, as the effort required for distributors to better understand their particular local circumstances when incentivising injection could also be useful for designing more efficient consumption pricing.

6.17. We propose that the change would not take effect until 1 April 2026 to allow time for distributors to consider how they will implement the change and to reduce risks noted above that would be more likely to arise if distributors had to implement the proposal on a compressed timeframe. We also acknowledge that distributors have to comply with Commission rules around Information Disclosure that mandate certain times and processes around changes to pricing methodologies.

6.18. Overall, we consider that the benefits of the proposal will significantly exceed the costs and potential risks.

Q15. Do you agree the benefits of the proposed amendment outweigh the costs?

The Authority has identified three other means for achieving the objectives

6.19. The Authority considered the following alternative options:

(a) maintain the status quo

(b) require distributors to provide injection rebates using prescriptive terms

(c) require distributors to provide injection rebates linked to the distributor's consumption charges.

The proposed amendment is preferred to other options

6.20. Maintaining the status quo is likely to result in inefficient investment and operation of DG, as distribution price signals for peak injection do not incentivise retailers to reward mass-market consumers for injection in circumstances where it benefits the network. While some networks may introduce such price signals under current regulatory settings, we consider that the level and rate of progress amongst distributors generally would not be sufficient.

6.21. A principles-based approach would provide this missing distribution price signal, which would result in the benefits described above. We consider the costs of this approach to be minor.

6.22. A more prescriptive rebate requirement would likely have similar benefits to our proposed option. To do so would require the Authority making certain decisions such as:

(a) precisely what potential future network constraints should be included when determining whether an ICP can provide network benefits (ie, based on how far into the future the constraint is likely to bind)

(b) whether rebates should be provided for a set period of time to provide investment certainty, and if so, how long this period should be

(c) the proportion of network cost savings that should be paid to the DG.

6.23. Rigid regulation around these decisions will inevitably result in circumstances where rebates do not appropriately reward injection for the benefit it provides, as they will not be tailored to individual circumstances.

6.24. We also consider that this approach may put prescriptive obligations on distributors that in some cases either cannot or should not be complied with, due to specific network factors – for example, if a distributor was required to determine the value of injection in relieving a constraint on its low voltage network where it did not have visibility. A principles-based approach gives distributors flexibility to take into account factors such as practicality and uptake incentives that would be hard to prescribe for in advance.

6.25. Consumption-linked injection tariffs would potentially provide a more even playing field between DG and demand response, as both would be rewarded similarly for the flexibility that they provide. However, as noted above in our discussion about this option, we are concerned that consumption charges are not sufficiently targeted to where a response would provide actual network benefits. As such, there is a real risk of over-incentivising injection, which (unlike over-incentivising demand response) can cause additional network costs. We therefore prefer a principles-based approach that provides rebates in a more targeted way.

6.26. Due to the workability issues associated with prescriptive rebates and the risks of consumption-linked rebates over-incentivising injection where it provides no network benefits, the Authority prefers our proposed option over these alternatives.

Q16. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority’s statutory objectives in section 15 of the Electricity Industry Act 2010.

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

6.27. Section 32(1) of the Electricity Industry Act 2010 (Act) says the Code may contain any provisions that are consistent with the Authority’s objectives and are necessary or desirable to promote one or all of the items set out in Table 1.

6.28. The Authority's main objective under section 15 of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The additional objective applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers.

6.29. The Authority considers the proposed amendments are consistent with its main objective for the reasons set out in this paper (by promoting competition, reliability, and efficiency).

6.30. The explanatory note to the Bill that led to Authority's additional statutory objective (to protect the interests of domestic consumers and small business consumers (small consumers)) indicated an intention that the additional objective not apply to how prices are determined. In addition, distribution pricing tends to apply as between a distributor and another participant (retailers) rather than directly to domestic or small business consumers. Nevertheless, the Authority considers the amendments to be consistent with the additional objective for the reasons set out above. In addition, by imposing requirements via the Code, the proposal would ensure that the principles could be enforced (for the benefit of small consumers) via the usual Code enforcement mechanisms.

Table 1: How the proposed amendments promote the items in section 32(1) of the Act

Item	How the proposed amendments promote the item
competition in the electricity industry	The proposed amendments aim to put mass-market distributed generation on more of a level playing field with mass-market demand response (which is already rewarded for the network benefits it provides) and with larger-scale, non-mass-market distributed generation (which is more likely to be rewarded through bespoke pricing arrangements).
the reliable supply of electricity to consumers	The proposed amendments will incentivise consumers to make decisions that help to minimise net peak demand and reduce the risk of a shortage. Further, the proposed amendments may incentivise consumers to invest in flexible DG such as batteries, which can provide resilience benefits to consumers.
the efficient operation of the electricity industry	The proposed amendments aim to improve the efficiency of investment in and operation of distributed generation, by incentivising injection when and where it will help avoid more expensive network investment in the future.

Item	How the proposed amendments promote the item
the protection of the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers	The proposed amendments, in conjunction with the proposals in our consultation paper 'Improving pricing plan options for consumers', protect the interests of domestic consumers and small businesses by improving their access to and uptake of price plan options that give them more choice about how they manage their electricity costs. Because the proposed principles would be contained in the Code, the usual Code enforcement mechanisms would be available to ensure compliance by distributors.
the performance by the Authority of its functions	N/A
any other matter specifically referred to in this Act as a matter for inclusion in the Code	N/A

The Authority has complied with section 17(1) of the Act

6.31. Under section 17(1) of the Act, the Authority, in performing its functions, must have regard to any statements of government policy concerning the electricity industry that are issued by the Minister. Table 2 below sets out our consideration of the Government Policy Statement on Electricity. [28]

Table 2: Consideration of the proposed amendments against the Government Policy Statement on Electricity

Clause	Consideration
14. Efficient network pricing is essential:	
a. To find the lowest cost solution, which may include demand-side response and flexibility to avoid or defer the need for network capacity augmentation; and	The proposal aligns with the Government Policy Statement as it seeks to incentivise investment in and operation of DG that avoids network costs.
b. For connections to enable efficient investment in new electricity consumption, including electrifying transport and process heat in industry.	N/A

[28] New Zealand Government. Government Policy Statement on Electricity - October 2024.pdf (beehive.govt.nz). Accessed 11 October 2024.

Clause	Consideration
15. As provided for under current arrangements: a. The Electricity Authority is responsible for setting principles (and regulating if warranted) for transmission and distribution pricing structures.	The proposal involves setting principles and regulating for distribution pricing structures.
32. The Electricity Authority is expected to work collaboratively with other agencies across the wider regulatory regime, acknowledging the scope of each agency's remit.	The proposal has particularly close interaction with the Commerce Commission's regulation of electricity lines services. We have also engaged with MBIE in their role as Task Force observer. We have collaborated at the policy development phase and anticipate collaborating through implementation - including via the Commerce Act s54V mechanism for price-quality path reconsiderations and the Electricity Industry Act s11 mechanism for Code exemptions.

The Authority has applied Code amendment principles

6.32. The Authority's Consultation Charter states that to provide greater predictability about decision-making on Code amendments the Authority applies certain Code amendment principles. Table 3 below sets out our consideration of the Code amendment principles.

Table 3: Consideration of Code amendment principles

Principle	Comment
Clear case for regulation: The Authority will only consider amending the Code when there is a clear case to do so	Problem definition is set out in this paper.
Costs and benefits are summarised	The costs and benefits of this proposal are summarised above.
Preference for small-scale 'trial and error' options	Not applicable, as all options considered here would apply to all distributors, with none involving trialling at a small scale first.
Preference for greater competition	All proposed options would put distribution pricing for mass-market DG on more of a level playing field (relative to the status quo) with: a) demand response from mass-market customers b) larger, non-mass-market DG.

Principle	Comment
Preference for market solutions	Not applicable, as all options considered here involve regulatory requirements for distributors to provide rebates. The Authority considers a purely market-led approach (ie, relying on distributors to contract for flexibility) has not led to sufficient progress in rewarding consumers for the benefits of their injection.
Preference for flexibility to allow innovations	Our preferred option gives distributors more flexibility to provide rebates in a way that best suits their network circumstances (including allowing for innovative solutions) than other more prescriptive options considered.
Preference for non-prescriptive options	Our preferred option (a principles-based approach) is less prescriptive as to how distributors must calculate and offer rebates than other options considered.

Appendix A Estimated financial impacts

A.1. Quantifying the impact of a principles-based approach, in terms of potential wealth transfer, is difficult. As discussed in paragraph 5.24, a principles-based approach allows distributors to reward injection in ways that take into account specific characteristics of a particular network. This will mean the level of rebate paid (and therefore the impact on both consumers who receive a rebate as well as on all consumers generally) will vary between distributors based on a range of factors.

A.2. However, we can approximate the impact of our proposal, particularly on consumers generally, by assuming that the total level of rebates a distributor would pay under a principled-based approach is similar to how much they would pay under a consumption-linked injection rebate approach. Rebates under a principles-based approach are likely to be much more targeted (ie, fewer rebates, but at a higher level), but we expect the total amount paid under the consumption-linked approach provides a useful starting point for estimating the consumer impact of our proposal.

A.3. This analysis indicates that consumption-linked injection rebates would provide a small increase in consumers' incentives to invest in battery storage, and that in the short term, this is likely to result in a much smaller increase in power bills for consumers without batteries.

A.4. A principles-based approach is likely to be more targeted, and therefore provide a stronger incentive to invest in batteries for those eligible to receive a rebate, with the impact on consumers generally remaining low, at least in the short term. While this impact on consumers generally may increase slightly in the medium term as more consumers invest in batteries and receive the rebate, in the longer term we expect this would reduce network investment requirements and therefore costs for all consumers.

Approach and methodology

A.5. We applied the analysis to all distributors that:

(a) had more than 100 residential ICPs with solar and battery installations as at 31 July 2024 (based on Electricity Registry data)

(b) had standard time-of-use distribution tariffs for the 2024 pricing year with approximately eight hours of peak period per day (to ensure alignment with our assumptions around how much electricity consumers use during peak times compared to off-peak times).[29]

Five distributors – Marlborough Lines, Powerco, Unison, Vector and WEL Networks – met these two criteria.

A.6. Our analysis followed the methodology below:

29 Most networks selected had peak periods between 7–11am and 5–9pm. WEL Networks had slightly different periods, which required adjustments to our assumptions around how much energy a residential consumer would be likely to use during these peak periods. While this may result in slightly less accurate analysis for this network, we consider the effect will be minor as the total number of peak periods (7 hours) is similar. Network Tasman was omitted from this analysis because it only had a day/night tariff.

(a) For each of the five networks, we estimated the average daily generation from an ICP with a solar and battery system during summer and winter periods, using the average installed capacity of the system on 31 July 2024. We assume all this generation occurs during the daytime off-peak period.

(b) Based on the average residential ICP consumption of 7,175 kWh per annum, we estimated the daily consumption for summer and winter periods, and how this is spread across the peak and off-peak time periods throughout the day.

(c) We assumed the energy from solar generation is firstly used to charge the battery, with any excess being used to offset consumption during the off-peak daytime period, and any further excess being injected into the network at the time of generation (ie, during the daytime off-peak period).

(d) We assumed the stored energy from the battery is then firstly used to offset consumption during peak periods (including both the evening peak period and the following morning peak period), with any excess being injected into the network during peak periods.

(e) Once we determined how much energy the average ICP injects into the network at peak times during summer and winter, we calculated the average amount paid by multiplying these figures by the respective rebate rate (noting that some distributors have different rates for summer and winter). The rebate rates are the difference between the variable charge for consumption at peak times compared to off peak times, multiplied by the adjustment factor of 50%. We then added the summer and winter amounts to get the average rebate (per ICP with solar and battery) for the whole year.

(f) We then multiplied this figure by the amount of ICPs with solar and batteries for each distributor to determine the total cost that each needs to recover.

(g) We assume these costs will be recovered through an increase in the charges that apply to all of the distributor's customers. We calculated this increase by dividing the total cost a distributor needs to recover by the total number of ICPs on its network (including those who receive the rebate).

A.7. We outline our key assumptions that apply to all distributors in the table below.

Table 4: Key assumptions

Variable	Assumption	Source
Solar PV capacity factor	15%	Electric-Homes-Technical-Report_March-2024.pdf
Seasonal generation split	Summer: 60% Winter: 40%	New Zealand Wind and Solar Generation Scenarios pg.3

Battery storage capacity	10 kWh with 70% depth of discharge (effective storage of 7 kWh)	EECA modelling assumption[30]
Average annual consumption per ICP	7,175 kWh	Average electricity consumption per ICP for New Zealand households - Figure.NZ
Seasonal consumption split	Summer: 40% Winter: 60%	EECA modelling results
Daily consumption split[31]	Morning peak (4hrs): 18% Daytime off peak (6hrs): 23% Evening peak (4hrs): 22% Night-time off peak (10hrs): 37%	EECA modelling results

Results

A.8. The forecast monthly rebates that would be provided to each consumers with a solar and battery system under the consumption-linked injection rebate option, across the five distributors we assessed, are presented below. We also show the increases in monthly charges for all consumers on the network that would be required for each distributor to recover the total annual cost of the rebate.

Table 5: Results of consumption-linked injection rebate

	Marlborough Lines	Powerco	Unison	Vector	WEL Networks
Average monthly rebate for an ICP with solar and battery system	$0.51	$0.51	$0.39	$0.0	$0.72
Average monthly increase in charges per ICP (all customers)	$0.00	$0.00	$0.01	$0.00	$0.01

A.9. As shown, the monthly rebates for the average consumer with a solar and battery system are very low under the consumption-linked tariff option, less than $1 for all distributors with an average of $0.43. This represents less than 1% of a consumer's

30 EECA has conducted complementary analysis investigating consumers' internal rate of return for investment in various distributed energy resources. Where possible, we have aligned our assumptions with those made by EECA in their analysis.

31 Excluding WEL Networks – see footnote 29.

standard monthly power bill.[32] This impact is low because batteries will tend to offset the consumer's own demand first, which tends to leave little electricity left over to inject into the grid. In particular, the analysis showed no rebate for the average Vector customer with a solar and battery system, as the rebate would only apply in winter (when peak consumption charges apply), during which times the average battery capacity would not be enough to offset the consumer's own consumption during peak times, so would not inject anything into the network at all. This means that under the consumption-linked injection rebate option, the incentive to invest in solar and battery systems, which tend to be an expensive investment, will be only marginally better than under the status quo. However, we note that under a principles-based approach, these rebates are more likely to be targeted, so while fewer consumers would be eligible to receive them, they would have a stronger impact on a consumer's incentive to invest in such systems.

A.10. The results also show negligible impacts on consumers without DG, with the monthly bill increase being no more than $0.01 per ICP when the cost of the rebate is spread over all the consumers on the network. This impact is likely to be similar for a principles-based rebate, as the total amount of rebate paid under a more targeted approach is likely to be similar (or possibly even lower).

Limitations

A.11. The analysis relies on several assumptions and has certain limitations, as described below. However, the Authority does not consider any of these undermine the overall conclusions.

(a) A key assumption is that under a principles-based approach, distributors will spend roughly the same amount on rebates as they would if rebates were linked to consumption charges. However, the degree to which a principles-based approach will result in more targeted rebates, and how this will affect the total amount paid, is difficult to determine.

(b) The analysis assumes perfect foresight and optimisation around when a battery should store energy and when it should discharge. In reality, the battery may not always be able to store and discharge optimally due to the uncertainty of household demand. This may lead to the battery being operated in a way that does not perfectly match our analysis.

(c) The analysis assumes an even generation profile throughout each season – ie, that the average generation output will occur every day. In reality, there will be some 'overs and unders' – however, above-average solar generation may not always be able to be fully stored (due to battery constraints), resulting in less injection than is needed to offset cloudy or rainy days when generation is below average.

(d) We have assumed there is no solar generation during the morning and evening peaks. However, during the summer mornings and evenings there will be some relatively small amounts of solar generation available.

[32] Based on MBIE QSDEP data: Electricity cost and price monitoring | Ministry of Business, Innovation & Employment.

(e) The analysis is based on the current levels of solar and battery penetration. This will increase as this measure incentivises solar and battery uptake. Our conclusions therefore apply to the short-term impacts of our proposal.

(f) We have assumed full retail pass through of both the rebate and the increase in charges for consumers generally to recover the costs of this rebate.

(g) The analysis assumes the cost recovery of the rebate will be evenly spread across all ICPs. In reality, distributors are likely to allocate more cost increases to larger customers (such as commercial and industrial ICPs) than smaller customers (such as residential ICPs).

Appendix B Proposed 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

1 Payments for injection

(1) A **distributor's** pricing methodology must:

(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 customer.

(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.

Q17. Do you have any comments on the drafting of the proposed amendment?

Appendix C Format for submissions

Submitter	

Questions	Comments
Problem definition	
Q1. Do you agree with the problem definition above? Why, why not?	
Proposed solution: principles-based rebates	
Q2. Do you agree with these principles? Why, why not?	
Q3. Do you agree that the principles should only apply to mass-market consumers, or should they apply to larger consumers and generators also? Why, why not?	
Q4. Do you agree the principles should apply to all mass-market DG, including inflexible generation (noting that the amount of rebate provided will still be based on the benefit the DG provides)?	
Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?	
Q6. Are there any additional issues with the principles where guidance would be particularly helpful?	
Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?	
Q8. Do you agree with the proposed implementation timeline for this proposal? If not, please set out your preferred timeline and explain why that is preferable.	
Q9. Do you agree the proposal strikes the right balance between encouraging	

price-based flexibility and contracted flexibility? Why, why not?	
Q10. Do you agree the proposal will lead to relatively minor wealth transfers in the short term, and will lead to cost savings for all consumers in the longer term?	
Alternative option: prescribed rebates	
Q11. Do you agree that more prescriptive requirements to provide rebates will be less workable than a principles-based approach, and therefore should not be preferred? Why, why not?	
Alternative option: consumption-linked injection tariffs	
Q12. Do you agree that a consumption-linked injection tariff would not be sufficiently targeted, and therefore should not be preferred? Why, why not?	
Q13. If this approach was progressed, do you think: a) injection rebates should perfectly mirror consumption charges? b) there are sufficient safeguards in place that would allow distributors to avoid over-incentivising injection to the extent that it incurs additional network costs?	
Regulatory statement	
Q14. Do you agree with the objective of the proposed amendment? If not, why not?	
Q15. Do you agree the benefits of the proposed amendment outweigh the costs?	
Q16. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objectives in section 15 of the Electricity Industry Act 2010.	

Proposed amendment Code drafting	
Q17. Do you have any comments on the drafting of the proposed amendment?	