Part 6: Pricing for Distribution Peak Export Tariffs

This Part provides guidance to Distributors on the development and implementation of peak export tariffs for consumers that export electricity back into their networks.

Introduction

Purpose and context

227. From 1 April 2026 distributors must offer a tariff that rewards consumers for injecting electricity back into the network at peak times— delivered through a negative charge credited to the consumer's retailer. This new requirement is set out in clause 12A.7 of the Code. The related consultation and decision papers can be found on the Authority's website: [New ways to empower electricity consumers | Our consultations | Our projects | Electricity Authority]

228. The negative charge applies to residential and small business consumers that supply electricity into a distributor's network at peak demand times of the day or the year, as determined by the distributor.

229. The purpose of the negative charge is to encourage consumers to supply electricity when it provides value to the network, and to reward them accordingly. The charge should reflect the value of avoiding or deferring network investment—on average and over time.

Structure of this guidance

230. This chapter of the Distribution Pricing Practice Note provides guidance to electricity distributors on implementing negative charges. It focusses on the first year of implementation, in which distributors have an option to set the negative charge based on their existing consumption pricing. Table 1 outlines the structure and key discussion areas for the guidance covered in this chapter.

231. This guidance builds on, and is complemented by, the other chapters of this Distribution Pricing Practice Note, which support distributors in setting prices that are efficient and non-distortionary.

Table 1: Table of contents for this chapter:

	Topic	Sub-topic
6A	The overall implementation framework	• Negative charges should provide broad, long-term signals • The Code provides pricing principles that give distributors flexibility in implementation • There is an optional transitional approach for the pricing year starting 1 April 2026 • Distributors must use a LRMC pricing approach on and after 1 April 2027 and beyond
6B	Consumers the negative charges must apply to	• Pricing categories the negative tariff applies to • Residential and small business consumers the negative tariff applies to • Distributed generation that qualifies as small business consumer • The negative charge must be applied across pricing regions (or pricing areas) • Linkages to the Low Fixed Charge Regulations

6C	Setting prices for the 1 April 2026 year using the transitional approach	• There are three key steps to setting prices using the transitional arrangement • Step 1: Identify the peak/off-peak price differential for consumption • Step 2: Determine the pricing window for the negative charge • Step 3: Determine an appropriate adjustment factor
6D	Setting prices using an LRMC approach	• Situations in which a LRMC approach in year 1 may be suited • Calculating LRMC-based negative charges • The guidance on the pricing window and adjustment factor similarly applies to a LRMC approach
6E	Wider considerations when setting negative charges	
6F	Considering non-price mechanisms for managing injection and network stability	
6G	Engaging with stakeholders	• Consultation is recommended but not required
6H	How compliance will be monitored	• Distributors must include negative charges in their pricing methodologies and posted tariff schedules • The Authority's role in monitoring and compliance • Information gathering and other powers • Granting exemptions from compliance

232. The text of clause 12A.7 of the Code requiring distributors' pricing methodologies to include this negative charge is as follows:

> **"12A.7 Payments for injection**
>
> "(1) A **distributor's** pricing methodology must, for any **price category** that has eligibility criteria that are designed to target residential or small business consumers, include a negative charge for injection of **electricity** into the **distributor's network** that:
>
> "(a) applies at times when demand in the region where the **ICPs** in that **price category** are located is likely to, on average and over time, drive future network investment; and
>
> "(b) is based on either—
>
> "(i) the long-run marginal cost of peak demand that can, on average and over time, be avoided by injection that occurs at the times identified in paragraph (a) from **ICPs** in that **price category**; or
>
> "(ii) for the pricing year beginning 1 April 2026, the difference between the peak charge and off-peak charge for consumption of **electricity** for **ICPs** in that **price category**; and
>
> "(c) has regard to transaction costs, consumer impacts, uptake incentives and network stability.

6A: The overall implementation framework

Negative charges should provide broad, long-term signals

233. Negative charges are intended to send broad, long-term signals to consumers rather than target specific network upgrades. By reflecting the long-run marginal cost of network capacity to meet peak demand, they reward electricity injections at peak times in a way that, on average, reduces network stress across the region. The focus is on collective behaviour over time, not individual actions or isolated investments.

234. These signals will encourage consumers to invest in batteries and other flexible resources, shifting injection toward peak periods. In aggregate, this reduces net peak demand, deferring or lowering the need for network expansion and delivering sustained, system-wide benefits.

235. However, negative charges should be set carefully, considering potential costs that could arise from injection, to ensure the signal is efficient and proportionate.

The Code provides pricing principles that give distributors flexibility in implementation

236. Distributors operate under differing network conditions, so the Code allows flexibility in how prices are set. The Electricity Authority has consistently taken a principles-based approach to regulating distribution pricing, rather than setting prescriptive rules. While the requirement to provide a negative charge is required under the Code, it still follows the same principles-based approach. Distributors can apply the principles in ways that suit their networks and customer base.

237. Negative charges should be guided by the same principles as distribution pricing more generally. The ultimate direction of travel is the same: towards pricing that reflects network conditions and provides signals that encourage efficient behaviour. Price signalling will vary—from no signal, to a strong signal incentivising specific actions—depending on circumstances.

238. Long-run marginal cost (LRMC) pricing is considered good practice because it links additional demand to long-run network costs, encourages efficient investment and consumption decisions, and helps avoid unnecessary network expenditure. Ideally, these price signals are location-specific, customer-specific, and aligned with peak demand periods.

239. However practical considerations remain important. Distributors must manage pricing complexity, avoid giving rise to secondary demand peaks, avoid undue price volatility, and give consumers time to adjust to cost-reflective tariffs.

There is an optional transitional approach for the pricing year starting 1 April 2026

240. Clause 12A.7(1)(b) of the Code gives distributors two options for setting their negative charge for the pricing year beginning 1 April 2026:

    1. Use the difference between peak and off-peak consumption charges for ICPs in the relevant price category; or
    2. Use the long-run marginal cost of peak demand that can, on average and over time, be avoided from injection at peak times, for ICPs in the relevant price category.

241. The first option is a transitional arrangement for the first pricing year. It recognises that some distributors will not have the systems, processes or data in place to implement a robust LRMC approach immediately.

242. Using the peak differential provides a short-cut that allows these distributors to meet the new requirement in the short-term, while allowing more time to develop a LRMC approach for the longer-term.

243. Distributors also have the option of using a LRMC approach from the outset, should they choose.

Distributors must use a LRMC pricing approach on and after 1 April 2027 and beyond

244. On and after 1 April 2027, all distributors must use LRMC to set negative charges, ensuring cost-reflective signals that promote efficient consumer behaviour and support efficient network investment.

245. We anticipate most distributors will adopt the transitional approach for 2026. For this reason, this note provides only high-level commentary on LRMC at this stage. We intend to provide further guidance on LRMC pricing—including its application to consumption and negative charges—in 2026.

246. We note there are a range of models and other sources available to distributors to support using a LRMC approach in lieu of our guidance, such as:

   1. Models provided by the ENA.
   2. Houston Kemp advice provided to Essential Energy on LRMC related to distribution pricing.[1]
   3. Information from other distributors that are already estimating LRMC in their pricing methodologies, for example Aurora Energy.[2]

247. Distributors should ensure any sources they use are reliable and robust.

Consumers the negative charges must apply to

Pricing categories the negative tariff applies to

248. The Code requires that a distributor's pricing methodology include a negative charge for every price category intended for residential and small business consumers.

249. The Code defines a price category as follows:

> **price category** means the relevant code in the schedule **published** by a **distributor** that is used to unambiguously define the line charges for an **ICP**

250. In practice, a price category is the tariff customer type in a distributor's pricing schedule. For example, in WEL Networks 1 April 2025 Tariff Schedule in Figure 1, price categories include Residential Low User – Time of Use, Residential Low User – Conditional, Residential Standard – Time of Use, and so on.[3]

Figure 1: Snapshot of WEL Networks' 2025 price schedule

www.wel.co.nz

WEL NETWORKS PRICE SCHEDULE

EFFECTIVE 1 APRIL 2025

WEL Networks

HOW TO USE THIS SCHEDULE

Customer groups are listed in tables with a breakdown of customer types, referred to as price categories. Where a price planoption is available for a customer it will be represented in a row within the table. Hence a single row applies to every customer. Eligibility criteria are detailed in the notes section below.

GLOSSARY

ICP: Installation Control Point – your point of connection to the network.

AMI: Advanced Metering Infrastructure

TIME PERIODS

TIME PERIODS	PEAK	SHOULDER	OFF-PEAK
Workdays	07:00 – 09:30 17:30 - 20:00	09:30 – 17:30 20:00 - 22:00	22:00 – 07:00
Weekends and public holidays (inc. Waikato regional holidays only)	No peak period	07:00 – 22:00	22:00 – 07:00

MASS MARKET PRICING

MASS MARKET	Estimated Number of Customers	Daily Fixed ($/day)	UNCONTROLLED SUPPLY				Controlled Supply ($/kWh)	Generation Export ($/kWh)
Fuse less than 110 kVA. Voltage 400V or less			Uncontrolled Supply ($/kWh)	Time of Use				
				Peak ($/kWh)	Shoulder ($/kWh)	Off-Peak ($/kWh)		
Residential Low User (1153)		501		806	805	804	503	555
Time of Use	49,898	0.7500		0.1529	0.0912	0.0792	0.0594	0.0000
Residential Low User (1153C)		C501	C502				C503	C555
Conditional	1,014	0.7500	0.0995				0.0594	0.0000
Residential Standard (1154)		501S		806S	805S	804S	503S	555S
Time of Use	36,564	1.8700		0.1018	0.0401	0.0281	0.0083	0.0000
Residential Standard (1154C)		C501S	C502S				C503S	C555S
Conditional	1,229	1.8700	0.0484				0.0083	0.0000
General (1200)		901		906	905	904	903	955
Time of Use	11,018	2.9100		0.1157	0.0788	0.0498	0.0342	0.0000
General (1200C)		C901	C902				C903	C955
Conditional	1,486	2.9100	0.0788				0.0342	0.0000

251. Each price-category may contain multiple charge components. In the case of WEL Networks' tariff schedule, these include the Daily Fixed Charge, Uncontrolled Supply, Controlled Supply, etc.

252. Distributors must provide a negative charge component for each price category targeted at residential and small-business consumers.[4]

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[1] Attachment-4_Economic-Report-from-Houston-Kemp.pdf

[2] Aurora Energy Pricing Methodologies

[3] price-schedule-2025.pdf

[4] In the relatively rare event a distributor has an ICP that is not capable of injected electricity, the negative charge need not be applied.

253. Once distributors consult on and publish their tariff schedules, retailers should automatically provide distributors with the required consumption and injection data for each ICP where the related sub-categories apply.

Residential and small business consumers that the negative tariff applies to

254. The Code requires a distributor's pricing methodology to include a negative charge for injection for every price category with eligibility criteria designed to target residential and small business consumers.

255. In practice, this means:

    1. Residential: Any price category that has eligibility criteria designed to target residential consumers must include a negative charge.
    2. Small business: Any price category that has eligibility criteria designed to target small business consumers must also include a negative charge.

256. If a price category does not have eligibility criteria targeted at residential or small business consumers, then a negative charge is not required. Distributors may choose to offer negative charges to other price categories if they wish, but are not obliged to.

257. A small business consumer is defined as per the Electricity Industry Act 2010 as a business that consumes less than 40,000 kWh per annum. If a distributor has a price category with eligibility criteria designed to target consumers that meet this definition, then a negative charge must be offered in that category.

258. However, we recognise that distributors may not distinguish consumers using kWh consumption, but instead rely on other measures such as capacity or fuse size. Distributors should therefore apply reasonable judgement when determining whether a price category has eligibility criteria that is designed to target small business consumers. To assist in this, we expect that the vast majority of small business customers using 40,000 kWh per annum would fall within a connection capacity of 69 kVA. We understand that this level of capacity is also a common capacity threshold that distributors often use for differentiating their commercial customers. We therefore recommend that distributors consider this the maximum capacity for small business consumers.

259. In the near future, we intend to consult on changes to the Code that would formalise this capacity limit for small business consumers to ensure this is the appropriate limit for distributors to use, and that the Code can be practically applied by distributors.

260. If a distributor does not have a distinct price category for small business consumers that meets this definition, then no negative charge needs to be offered. For example:

    1. A general commercial price category that encompasses all of a distributor's business consumers, regardless of size, does not require a negative charge.

    261. Where a distributor has multiple commercial consumer categories, but the price category that most small business consumers fall into does not have eligibility criteria that were designed to target small business consumers, and consequently may include a broader range of consumers that are not small businesses, then no negative charge needs to be offered.

262. The intent is to capture price categories that explicitly provide for small businesses. Distributors do not need to take action if some small businesses are included in a broader category that is not offered the negative charge, if that category was not designed specifically for small businesses.

Distributed generation that qualifies as small business consumer

263. We expect that setting a maximum 69 kVA capacity limit for small business consumers will mean that large distributed generation (DG) customers that could inject significant amounts of power into the network will be excluded from the definition of a small business consumer and from receiving the

negative charge. This is consistent with the policy set out in our consultation paper and decision paper, which noted that the principles should apply to injection from mass market customers only.[5] As noted above, we intend to consult on changes to the Code that would formalise the 69 kVA capacity limit for small business consumers to ensure this is the appropriate limit for distributors to use, and that the Code can be practically applied by distributors.

264. The small business DG customer may already receive payments for their injection. If a distributor must offer a negative charge to DG in that price category, they may wish to consider changes to their existing payments to that DG to account for that new negative charge alongside existing payments. This is a commercial decision for distributors to consider and we do not provide further guidance on this.

265. If the provision of the negative charge incentivises greater DG injection at peak times and there is a risk of this leading to 'herding' behaviour that causes excessive injection, and therefore export congestion or voltage problems, then we suggest this risk may be managed through both the adjustment factor when setting the negative charge and non-price mechanisms for managing injection and network stability. These topics is discussed later in this guidance.

The negative charge must be applied across pricing regions (or pricing areas)

266. Clause 12A.7(1) of the Code requires distributors to offer a negative charge for injection that applies when demand in the *region* where the ICPs in the price category are located is likely to drive future network investment. The term "region" relates to a distributor's geographic pricing regions used for pricing categories that target residential and small business consumer ICPs. For example, Aurora Networks has three pricing regions – Dunedin, Central Otago and Queenstown/Wanaka.

267. Negative charges must be aligned with these pricing regions, which should already be differentiated and described in each distributor's pricing methodology.

268. Distributors have discretion over how to divide their networks into pricing regions for residential and small business consumer ICPs. If a distributor wants to implement a more targeted negative charge for a smaller geographic area, it could consider creating a new pricing region. This may be appropriate where the cost drivers in different parts of the network differ materially, justifying distinct price signals (for injection, and likely also consumption). However, distributors must trade off the benefits of accuracy against practical considerations and stakeholder views, and determine the appropriate balance for their network.

Linkages to the Low Fixed Charge Regulations

269. Cabinet was recently approved an amendment to the LFC Regulations. This is found here: Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2025 (SL 2025/215) Contents – New Zealand Legislation.

270. As described in the explanatory note, this amendment creates an exclusion for any tariff option where the consumer receives a credit or payment for electricity they inject back into the network (an injection payment tariff option). If a tariff option is an injection payment tariff option, it will not meet the definition of an alternative tariff option or an alternative distributor tariff option under the principal regulations. The exclusion only applies if a distributor makes available at least one alternative tariff option or alternative distributor tariff option that is not an injection payment tariff option.

271. The effect of this amendment is that any injection payment tariff option offered by a retailer or distributor, including those imposed by the 2A requirements, will be excluded when assessing

[5] Refer paragraph 5.50 of our Decision Paper - 2A_Requiring_distributors_to_pay_a_rebate_when_consumers_supply_electricity_at_hYzYEsJ.pdf, and paragraph 5.5 of our Consultation Paper: 2A_Requiring_distributors_to_pay_a_rebate_when_consumers_supply_electricity_at_hYzYEsJ.pdf

whether a low fixed charge tariff option or a regulated distributor tariff option complies with the LFC Regulations.

6C: Setting prices for the 1 April 2026 pricing year using the transitional approach

There are three key steps to setting prices using the transitional arrangement

272. Clause 12A.7(1) of the Code requires that the negative charge:
    1. Is based on the difference between the peak charge and off-peak charge for consumption of electricity for ICPs in the price category
    2. Applies at times when demand in the region where the ICPs in the relevant price category are located is likely to, on average and over time, drive future network investment.
    3. Has regard to transaction costs, consumer impacts, uptake incentives and network stability.
273. As such, the method for calculating the negative charge using the interim option based on peak and off-peak consumption tariffs is:
    1. **Identify the peak/off-peak price differential for consumption**
    2. **Determine the pricing window for the negative charge**
    3. **Determine an appropriate adjustment factor**
274. Each of these steps is discussed in turn. Steps 2 and 3 apply equally to a LRMC approach to setting the negative charge.

Step 1: Identify the peak/off-peak price differential for consumption

275. As a first step in setting negative charges under the transitional approach, distributors should calculate the difference between their peak and off-peak prices for consumption on 1 April 2026, for each pricing category the negative charge applies to.
276. For example, if the standard peak rate is $0.17/kWh and the standard off-peak rate is $0.02/kWh, the differential is $0.15/kWh. The differential forms the starting point for determining the negative charge.
277. Any price that applies to a shoulder period can be ignored.
278. For distributors that do not have peak/off-peak pricing but have a Day/Night tariff—even if that tariff is not broadly assigned—the differential can be established as the difference between the Day and Night rates.
279. The Code specifies that LFC tariffs must not be used for the purpose of this calculation.

Step 2: Determine the pricing window for the negative charge

280. Distributors should apply principles-based adjustments to account for specific network conditions, including through considered selection of the pricing window. The pricing window is those periods of time (hours/days/months) that a distributor determines are when demand on its network is at its greatest and when additional demand is likely to drive future network investment, and on that basis it decides the negative charge will apply.
281. The phrase *"on average and over time"* means that the negative charge should apply during periods when electricity injections are most valuable for the network. This is because over the long term, growth in demand during those periods would require new investment (e.g., capacity upgrades) that could be avoided or deferred by a collective consumer response.
282. As a starting point, distributors should use the peak periods already applied in their consumption tariffs. Distributors' consumption tariffs should already be structured to reflect times of highest demand and LRMC. In most cases, we expect negative charges will therefore align with the daily and/or seasonal peak pricing windows of consumption tariffs.

283. However, clause 12A.7(1) does not mandate specific time periods when the negative charges must apply. It requires that charges apply at times when demand is likely, on average and over time, to drive future investment. Distributors may therefore depart from specifically matching the consumption peak periods if alternative time periods would deliver greater efficiency benefits. This could include, for example:

    1. Defining a narrower window, where injection from residential and small business consumers would be most likely to reduce future network investment.
    2. Applying negative charges only during particular months of the year when peak demand is most likely to drive future network investment. For example, distributors may wish to narrow the window in order to avoid times when there is already significant injection from solar generation in certain parts of the network, such as early evening in summer (particularly if encouraging further injection at such times would be likely to *increase* future network investment).

284. This flexibility applies to both the transitional approach for the first year of implementation (1 April 2026), and to subsequent years under the LRMC-based approach.

285. Where distributors adopt windows that do not directly overlap with their corresponding consumption tariffs, we would expect them to document a clear rationale in their pricing methodology.

Step 3: Determine an appropriate adjustment factor

286. Clause 12A.7(1)(c) of the Code allows distributors to apply an adjustment factor to negative charges. This should scale the negative charge down relative to the peak/off-peak consumption differential, to reflect the specific risks and characteristics of injection with regard to transaction costs, consumer impacts, uptake incentives, and network stability. For example, if a peak/off-peak consumption differential of 10c/kWh had an adjustment factor of 60% applied to it, the negative charge would be 4c/kWh. Distributors should adopt an approach they can explain clearly and support with reasons in sufficient detail in their published pricing methodologies.

287. The application of this adjustment factor should ensure that tariffs are both cost-reflective and adaptable to changing conditions.

288. The characteristics of injection from distributed generation differ to that of a demand-side response, and hence justify a different signal. Specifically:

    1. Large or synchronised injection at any single time or location may impose additional network costs (e.g., congestion management, voltage control, and protection system upgrades) whereas demand response may reduce overall efficiency if poorly targeted, but it does not create new network costs in the way unmanaged injection can.
    2. Distributed generation is also likely to be more responsive to price signals. Batteries can be programmed to respond to precise signals. This could induce ‘herding’ behaviour that causes excessive injection, and therefore export congestion or voltage problems. In contrast, demand-side response can require more effort on behalf of the consumer, and can have a different cost/benefit trade off.
    3. The number of consumers capable of injecting electricity is currently low, but has significant potential for rapid growth. This contrasts with network demand, which is well-established and typically grows more incrementally.
    4. The LFC Regulations and ongoing programme of distribution pricing reform mean that consumption charges are not yet fully cost-reflective (e.g., off-peak usage rates may still be higher than a truly cost-reflective rate).

289. It is up to each distributor to determine an adjustment factor that reflects the realities of their own network. The right setting will depend on both the risks of over-incentivising injection and the value of encouraging it to offset long-term demand growth. In assessing this, distributors should weigh:

1. The extent to which their consumption pricing—and hence the differential—is cost-reflective, or may change with future pricing improvements (including the move to a LRMC approach to setting negative charges from 1 April 2027).
2. The magnitude of their peak/off-peak price differential, and hence the size of adjustment necessary to ensure a price signal that the distributor is confident will not have unintended consequences.
3. The potential for local injection constraints – including:
   i. whether specific parts of the network are at risk of congestion or voltage issues if injections cluster at the same time
   ii. the potential for these localised constraints to create costs before longer-term network wide benefits from reduced peak demand can be realised
   iii. their potential to be exacerbated by a negative charge
   iv. the potential for them to be managed through non-price factors (see paragraphs 287-293), a more targeted pricing window, or a change to pricing regions.
4. Expected uptake of distributed batteries and other flexible technologies on their networks – and the likely responsiveness of these devices to price signals.
5. Visibility of the low-voltage network – which affects a distributor's ability to anticipate, monitor, and manage injection-related issues.
6. The pace of peak demand growth – as faster demand growth strengthens the value of incentives to shift injection into peak times.
7. Coordination opportunities – such as whether distributors have means to contract with aggregators or flexibility providers to manage injection more directly, which may reduce the value of a broad price signal (but does not justify no signal).
8. The availability of and interface with other tariffs that the distributor may already have that reward injection.

290. Given the broad range of circumstances that New Zealand's distributors face, the Authority does not consider it possible to give prescriptive guidance on an appropriate range for the adjustment factor. We note that the credit scheme trialled by Aurora effectively used a 50% adjustment factor. Australian distributors use a range of adjustment factors ranging from around 10% to over 70%. We consider that a wide range of potential adjustment factors can be justified, depending on circumstance.[6] Distributors should adopt an approach they can explain clearly and support with reasons in sufficient detail in their published pricing methodologies.

291. When distributors set out how they have developed their adjustment factors in their pricing methodologies, we expect they will provide a qualitative discussion on each of the factors that have been considered, including those described above. This should also include evidence where this is available, and the relative weight of importance that each factor has been given when developing the adjustment factor. It may also be beneficial to include a commentary on any factors that have not been considered relevant in their assessment of the adjustment factor and why.

292. We consider it prudent to begin with a relatively high adjustment factor (and therefore lower negative charge) at the outset, and to fine-tune it over time as better data and consumer feedback become available. It is much easier to strengthen incentives later than to scale them back once consumer expectations and investment decisions have been shaped. It also reduces the risk of over-incentivising injection, while allowing stronger signals to develop over time.

[6] Our Consultation Paper Requiring distributors to pay a rebate when consumers supply electricity at peak times p.28 noted that 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%.

293. Where a distributor has relatively low growth across its network and limited or few forecasted constraints driving system growth capital expenditure, they may consider their LRMC is likely to be low or close to zero. In this situation, a distributor may consider use of a high adjustment factor. Evidence that to support such factors should include

1. references to the company's asset management plan forecasts of peak demand versus network capacity,
2. references to forecasted system growth capital expenditure, and
3. assumptions around the forecasted amount of battery and solar uptake on the network.

294. The Authority will monitor and review each distributor's adjustment factor to ensure it is appropriate, sufficiently explained, and justified in their pricing methodologies. We may also, from time to time, publish updated guidance and adjustment factor parameters as injection grows and pricing matures.

6D: Setting prices using a LRMC approach

Situations in which a LRMC approach in year 1 may be suited

295. While it is entirely up to each distributor whether to adopt a LRMC approach for the 1 April 2026 pricing year, we would only encourage it where:

1. The distributor already has a mature LRMC methodology for consumption pricing that it is confident in; or
2. The distributor is advanced in developing a LRMC approach, so the incremental effort to apply it to negative charges is relatively small.

296. These circumstances reduce implementation risk and allow distributors to provide early, credible long-term price signals without overcomplicating the first-year rollout.

Calculating LRMC-based negative charges

297. Should distributors wish to use the LRMC approach in the first year of the negative charge, they may use LRMC guidance and models from a range of sources, noting that distributors should ensure these sources are reliable and robust. For example, we note the ENA has published advice on LRMC, and the Houston Kemp advice to Essential Energy on LRMC related to distribution pricing.[7] Other sources of guidance can include what other distributors are doing to estimate LRMC in their pricing methodologies, for example Aurora Energy.[8] Distributors should ensure any sources they use are reliable and robust.

298. A pricing approach based on the long-run average incremental cost is considered a form of LRMC pricing, and hence is consistent with the Code.

The guidance on the pricing window and adjustment factor similarly applies to a LRMC approach

299. When using a LRMC approach, the guidance above about determining an appropriate pricing window and adjustment factor equally apply (though noting the outcomes may be different).

6E: Wider considerations when setting negative charges

300. When setting negative charges, distributors must balance efficiency with practicality. The Code (clause 12A.7(1)(c)) specifically requires consideration of transaction costs, consumer impacts, uptake

[7] Attachment-4 Economic-Report-from-Houston-Kemp.pdf

[8] Aurora Energy Pricing Methodologies

incentives, and network stability. These are not only relevant to the adjustment factor, but also to the broader design of distribution pricing. Distributors should weigh these factors when choosing, as outlined above:

1. the granularity of pricing regions
2. the peak periods selected for the negative charge
3. how the negative charge tariff is structured
4. the specific LRMC approach to adopt (if taking that approach).

301. In each case, distributors should consider:

    1. Transaction costs: There are trade-offs between accuracy and simplicity. The selection of LRMC approach is an example of this trade-off. Similarly, more granular pricing regions or narrower peak pricing periods may result in more cost reflective charges, but at a risk of complexity and higher costs to retailers and consumers that could have adverse effects on retail competition. Negative charges should be not designed at a level of granularity where transaction costs are likely to outweigh efficiency gains.
    2. Consumer impacts: Pricing reform is a journey, not a step change, and distributors should be conscious of how changes to pricing are likely to affect consumers. As set out in this Practice Note:

        > *“price shocks are not a desired outcome of pricing reform, and the Authority is cognisant of the need for prices to evolve on a journey towards efficient outcomes, rather than rush to an endpoint.”*

        This may mean starting conservatively and ramping up over time. Distributors should also be mindful of how benefits are shared between injecting and non-injecting consumers.
    3. Uptake incentives: The effectiveness of the injection signal depends on retailers passing it through to consumers. Price signals that are too granular, unique, complex, volatile, or poorly aligned with wholesale price signals, are less likely to be passed through effectively. Conversely, too weak a signal may not be passed through at all. Distributors should aim for a balance that is both meaningful and practical.
    4. Network stability: Broadly averaged negative charges risk creating export congestion or voltage issues in specific locations. Distributors should consider the full range of options available for managing these issues – including targeting by time, location, or capping the eligible injection volume when seeking to mitigate these risks. Technical standards may also be relevant.

302. Distributors’ pricing methodologies must set out how they have considered these factors when determining their negative charges, including any underlying considerations and assumptions.

303. Distributors should refer to the further guidance set out in Part 2 of this Practice Note on these issues.

6F Considering non-price mechanisms for managing injection and network stability

304. Clause 12A.7(1) of the Code requires distributors to have regard to network stability when developing their negative charges. Excessive injection at a particular time or location could compromise network operations, affecting reliability and equipment lifespan.

305. In addition to pricing measures, distributors can manage injection through export limits. These limits help ensure networks operate within prescribed limits (e.g., voltage levels) to ensure reliable supply to network users, and to optimise the life of network equipment.

306. Export congestion risk may differ across the network. Distributors should apply different restrictions in different areas, reflecting local conditions. The benefits of a granular approach should be balanced against any additional costs of managing it. Distributors also can specify individual export limits and the reasons for these (which are often identified during network studies as part of assessing the

application to connect distributed generation), as part of any conditions when approving individual applications.

307. There are three basic types of export limits that distributors could apply:

1. **Static export limits:** Fixed 'caps' on how much electricity can be injected that are in effect at all times of the day. These may apply to a class of applications (e.g., household solar), parts of a network, or the network as a whole.
2. **Dynamic export limits:** Flexible limits that adjust in 'real-time' to network conditions. For example, voltage response modes in inverters automatically reduce export when network voltage arises.[9] All distributors currently set dynamic export limits for distributed generation, generally through specifying the AS/NZS Standard for inverters (4777.2) including the voltage response modes contained in the standard.
3. **Bespoke export limits:** Tailored limits for larger generation connections, determined through network studies. The distributor may require export limiters to be installed in some cases.

308. While not explicit, Part 6 of the Code allows distributors to set static, dynamic and bespoke export limits through their published 'connection and operation standards' (COPS).[10] COPS also include congestion management policies, which means the policies, describing the circumstances under which distributed generation may be curtailed.[11]

309. In addition, in June 2025 the Government amended the Electricity (Safety) Regulations 2010 to expand the allowable low voltage supply range from 230V ±6% to 230V ±10%. This change is expected to take effect in 2025/26, allowing distributed generation owners to export more electricity to networks, to deliver broader benefits.

310. The Authority sent an open letter to distributors outlining its expectations that they revise and update their processes and settings to give effect to the new voltage limits.[12] This includes revising planning, design, connection and operation standards, as well as practices and guidance for connecting to networks.

6G: Engaging with stakeholders

Consultation is recommended but not required

311. The new Code requires distributors to include a negative charge for injection in any price category that has eligibility criteria that are designed to target residential or small business consumers.

312. Clause 7.2(c) of the Default Distributor Agreement template[13] (and the corresponding provisions in distribution agreements based on this template) allows distributors to change their price categories at any time provided that the change does not have the effect of increasing one or more prices.

313. This overrides the general consultation requirement in clause 7.4 relating to changes to pricing structures. Because the new Code requirement requires the inclusion of negative charges for injection, this should not result in an increase to prices. Therefore, consultation is not required on these charges.

314. However, irrespective of whether consultation is required, it may be prudent to consult on the implementation of the new Code requirement with affected traders and customers as this could provide an opportunity for any disagreements over distributors' interpretation and implementation

[9] An inverter is a device that converts direct current (DC) electricity, produced by most distributed generation types (eg, solar), into alternating current (AC) electricity as used in New Zealand.

[10] Part 6 applications must meet these standards – see Part 1 of the Code (Preliminary provisions) for the definition of COPS: https://www.ea.govt.nz/documents/7968/Part_1_-_Preliminary_provisions_-_31_July_2025.pdf

[11] See clause 6.3(2)(d) of the Code

[12] https://www.ea.govt.nz/documents/7496/Open_letter_to_distributors_-_13_June.pdf

[13] Appendix A of Schedule 12A.4 of the Code.

of the new Code requirement to be surfaced and dealt with early, thus avoiding potential Code breach disputes in future.

315. Finally, clause 12A.7(5) of the new Code requirement applies despite anything contrary in any agreement or the regulated terms. Where a distribution agreement is inconsistent with the new Code requirement, the Code obligation takes precedence.

6H: How compliance will be monitored and enforced

Distributors must include negative charges in their pricing methodologies and posted tariff schedules

316. Clause 12A.7(3) of the Code, requires distributors to include in their pricing methodologies:

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

317. We encourage distributors to make this information available for each price category and pricing region.

318. We also encourage distributors to provide in their pricing methodologies the following:

i. Details of how the negative charges were derived if this used the interim approach of the differential of the peak and off-peak prices, including the specific tariffs used.
ii. The rationale for the price periods chosen that the negative charges apply to.
iii. Linkages to the inputs and planning horizons taken from the Asset Management Plan that have been used to develop the LRMC based negative charges.
iv. What adjustment factors have been used, the assumptions and rationale for their use, and how the adjustment factors may change over time.
v. Non-pricing measures that have been used to ensure network stability.

319. Negative charges must all be included in the distributor's pricing schedules posted under the Commerce Commission's Information Disclosure requirements.

The Authority's role in monitoring and compliance

320. The Authority is responsible for monitoring and enforcing compliance with the Code. This includes:

1. monitoring compliance through receipt and analysis of distributors' annual pricing methodologies
2. analysis to ensure that the requirements are functioning as intended and benefiting consumers without imposing undue costs
3. enforcing serious breaches, where appropriate through the Rulings Panel.

321. We adopt a targeted enforcement approach undertaken in accordance with the Electricity Industry (Enforcement) Regulations 2010 and relevant enforcement and compliance policies, which are available on our website.

322. Under the Act, the Rulings Panel has the power to make a range of remedial orders if a participant breaches the Code, including requiring a participant to pay a pecuniary penalty not exceeding $2

million (plus a further amount of up to $10,000 per day for ongoing breaches), and making a compensation order requiring a participant to pay a sum by way of compensation to any other person.[14]

Information gathering and other powers

323. The Authority also has powers to gather information from participants for the purpose of monitoring compliance with the Code.

324. The Authority has the power to require an industry participant to:

    1. provide information, papers, recordings, and documents that are in the possession, or under the control, of the participant
    2. permit its officers or employees to be interviewed
    3. give all other assistance that may be reasonable and necessary to enable the Authority to carry out its functions and exercise its powers.

325. The processes that the Authority will apply in respect of these information gathering powers are described in the Authority's Guidelines on Information Gathering Powers under the Electricity Industry Act 2010.

Granting exemptions from compliance

326. Section 11 of the Act gives the Authority the power to exempt a participant from complying with their obligations under the Code.

327. To grant a Code exemption, the Authority must be satisfied that:

    1. it is not necessary, for the purpose of achieving the Authority's objectives under section 15, for the participant to comply with the Code or the specific provisions of the Code; or
    2. exempting the participant from the requirement to comply with the Code or the specific provisions of the Code would better achieve the Authority's objectives than requiring compliance.

328. An overview of the Code exemption process is outlined in the Authority's separate guidelines on Code exemptions, available on the Authority's website: Exemptions and dispensations | Electricity Authority

[14] Section 54 of the Act.

Appendix A Glossary

Authority means the Electricity Authority, being the Crown entity established under section 12 of the Electricity Industry Act 2010 to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers

Avoidable costs are those costs that can be avoided by not serving a customer or customer group. Examples of avoidable costs include billing and customer service costs, connection costs specific to the customer or customer group, and additional maintenance costs

Consumer groups means for pricing purposes, consumers grouped to have similar characteristics, similar network costs, and similar consumption profiles. Consumers within a group are typically subject to the same pricing plan

Customer means a person who has entered into a contract with a retailer for the supply of electricity, other than for resupply, and/or the provision of distribution services, where the electricity supplied to the customer's premises is used fully or partly for domestic uses

DER means distributed energy resources and refers to resources on the network that do not connect to the transmission grid, such as solar PV, energy storage systems and demand response

Distribution services mean the conveyance of electricity on lines, as defined in the Electricity Industry Act 2010, by a distributor

Distributor has the meaning given to it in section 5 of the Electricity Industry Act 2010.

Economic costs are costs of providing the service, and any additional costs (externalities) borne by others (but not the producer)

ENA means Electricity Networks Aotearoa

ERGANZ means the Electricity Retailers' and Generators' Association of New Zealand

EV means an electric vehicle, both hybrid and fully electric, that has a battery which has the ability to be recharged from the distributor's network

Fixed costs are invariant to the level of output, eg costs that are invariant to the amount of electricity sent down a network

ICP Installation control point – a point of connection at which the electrical installation for a retailer's customer is connected to a network

LFC regulations means the Electricity (Low Fixed Charge Tariff Options for Domestic Consumers) Regulations 2004

Locational marginal pricing is pricing at different locations in the network, reflecting local demand and capacity, and the cost of getting electricity to a particular location

Long-run Marginal Cost (LRMC) – the incremental cost associated with expanding a distributor's network to meet growth in peak demand, expressed as $/kW or $/kVA, and then converted into $/kWh.

Marginal cost is the additional cost of producing one extra unit. In the context of distribution, typically the additional cost of serving one additional customer to the network, or the additional cost of increasing network capacity

Non-network alternatives are alternatives to investments in transmission and distribution, often to manage capacity constraints. Examples include demand management, interruptible demand, distributed generation, batteries, etc.

Non-distorting is an action or price is non-distortionary if it does not change the behaviour of consumers or producers

PV means Photo voltaic, or solar panels

Residual revenue / residual cost is revenue that augments the revenue obtained from cost reflective pricing to ensure that fixed costs can be covered, so that firms do not make a loss. (Residual costs for consumers = residual revenue recovered by distributors.)

Retailer has the meaning given to it in section 5 of the Electricity Industry Act 2010

Revenue targets are the levels of revenue that distributors aim or are permitted to obtain, eg as determined by price-quality paths set by the Commerce Commission (where applicable)

Ripple control is demand management of consumer power consumption based on remote control of hot water cylinders

Smart Meter means a meter that is able to communicate information about the consumption and injection of electricity during peak versus off-peak times during a day.

Standalone costs are the costs needed to replicate or bypass a network entirely. If electricity prices are greater than a consumer's standalone cost then the consumer is better off by disconnecting from the electricity network and, for example, generating their own electricity or sourcing it elsewhere

Subsidy-free prices are subsidy-free if they fall below standalone cost but are above incremental cost. A consumer paying a subsidy-free price makes some contribution to a distributor's fixed cost