ENA submission on ECTF initiatives 2a, 2b and 2c and Authority DGPP issues paper

Combined submission to the Electricity Authority & Energy Competition Task Force

DATE
26 March 2025

NAME OF SUBMITTER
Electricity Networks Aotearoa

INDUSTRY/AREA OF INTEREST
Utilities/infrastructure

CONTACT
Gemma Pascall, Regulatory Manager

ADDRESS
[redacted]

TELEPHONE
[redacted]

EMAIL
[redacted]

āhuarangi. kiritaki. mahi ngātahi.
climate. customers. collaboration.

Contents

1	Introduction	3
2	Executive summary	4
3	Key themes and interdependencies	11
Appendix A: ENA Members		33
Appendix B: Initiative 2a – Requiring distributors to pay a rebate when consumers supply electricity at peak times		34
Appendix C: Initiative 2b & 2c – Improving pricing plan options for consumers – time-varying retail pricing for electricity consumption and supply		39
Appendix D: Distributed generation pricing principles issues paper		43

1 Introduction

Electricity Networks Aotearoa (ENA) welcomes the opportunity to make a submission on recent consultation papers. Given the interdependencies between the package of papers released on 12 February 2025, this submission combines feedback on the following consultations:

- Energy Competition Task Force Initiative 2a – *Requiring distributors to pay a rebate when consumers supply electricity at peak times* (2a paper or 2a proposals)
- Energy Competition Task Force Initiatives 2b & 2c – *Improving pricing plan options for consumers – time-varying retail pricing for electricity consumption and supply* (2bc paper or 2bc proposals)
- Electricity Authority's *Distributed generation pricing principles issues paper* (DGPP paper or issues paper)

ENA is the industry membership body that represents the 29 electricity distribution businesses (EDBs) that take power from the national grid and deliver it to homes and businesses (our members are listed in Appendix A).

EDBs employ over 7,800 people, deliver energy to more than two million homes and businesses, and have spent or invested $6.2 billion in network assets over the last five years. ENA harnesses members' collective expertise to promote safe, reliable, and affordable power for our members' customers.

2 Executive summary

ENA supports the intent of the Energy Competition Task Force (ECTF or Task Force) and Electricity Authority (Authority), to increase the security of supply and lower costs to consumers, through supporting more small-scale solar and battery investments and requiring retailers to offer more time-of-use plans. We also support the intent of reviewing the associated distributed generation (DG) pricing principles (DGPP).

The principles of the proposals appear to be (economically) sound,[1] but there are likely to be genuine and material implementation issues that need to be carefully considered and addressed to ensure the proposal doesn't become another version of ACOT (lots of payments, with little actual benefit or even over-incentivising the wrong behaviours).

As highlighted in the ENA's 2021 submission on the Authority's *updating the regulatory setting for distribution networks*[2] consultation paper, EDBs see distributed energy resources (DER) and flexibility services delivering benefits to consumers in the coming decades. DER will grow to become a fundamental part of the electricity sector as it adapts to facilitate the low-carbon economy.

ENA members are playing their part in this evolution and are preparing for the ramp-up of DER, and the development of flexibility services. In creating an environment conducive to DER and flexibility services, ENA and its members view distribution prices and an enabling regulatory regime as inextricably entwined, rather than being standalone pillars. Sending the correct price signals, via distribution prices, will play a crucial role in enabling the efficient deployment of DER and adoption of flexibility services.

However, as we discussed in 2021,[3] it is unclear if cost-reflective distribution prices alone will support the financial viability of flexibility services beyond those that allow EDBs to avoid network expenditure.

2.1 Empowering consumers to make informed choices

ENA supports improving price signals and providing more choices for consumers. We agree with the ECTF's view that consumers should "have greater control over their energy use and costs."[4]

We appreciate the ECTF's proposal, recognising that household generation is crucial to the future energy system. The true value of solar energy is realised when combined with batteries, enabling flexible demand shifting. The primary advantage for consumers is avoiding peak consumption charges through self-consumption, with the export value being a secondary benefit.

We also support consumers having a choice regarding time-of-use (TOU) pricing. It is important that consumers are aware of this choice and can either opt into a TOU plan if it aligns with their preferences, but equally also opt out of such a plan. For some, it is not easy to shift load out of peak periods and therefore a TOU plan might actually *increase* their bills. Others may simply value the certainty that a flat-rate tariff (or all-you-can-eat offer) provides.[5]

---

[1] Subject to some interpretation clarifications detailed further in this submission

[2] ENA, Submission updating the regulatory settings for distribution networks, 28 September 2021

[3] ENA, Supporting reform to efficient distribution pricing, 3 November 2021

[4] ECTF, Improving pricing plan options for consumers, 12 February 2025, page 6, paragraph 1.2

[5] A flat tariff can also be cost-reflective

2.2 Not all exports generate benefits

ENA agrees with the ECTF that distributed generation, such as rooftop solar, other types of small-scale electricity generation or 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 and reliably, it can reduce a distributor's need to invest in additional network capacity as demand on the network grows. This can, in turn, reduce costs for the network, reducing costs for all consumers in the long run.

However, as the ECTF also rightly acknowledges, exports at the wrong times and places in the network can increase costs for networks.[6] There is also an established precedent that generation/export should also pay for network use and not 'free ride',[7] a point emphasised in the DGPP issues paper.[8]

It is also important to note that congestion is temporal and, in many cases, transitory, which poses significant challenges to EDBs and flexibility service provider business models, particularly where they involve capital outlay for long-lived assets (e.g. on-premise batteries). Current pricing regulations, and the changes proposed in these papers, do not give EDBs an ability to respond to temporal and transitory congestion. EDBs will set prices 18-24+ months ahead of time. If network needs change, it is generally going to be at least 1.5-2 years until EDB pricing can be adjusted to incentivise behaviour to address the new network needs.

Should the proposal proceed, we therefore think that the inclusion of the provision in the proposed 2a amendment that rebates should only be paid "at times when the injection provides network benefits" is vital in the ECTF's final decision. Failure to include that proviso would, as noted in the 2a paper, risk "unintended and inefficient subsidies… ultimately funded by other consumers."[9]

2.3 Consumer behaviour should be appropriately incentivised and rewarded

ENA supports fair returns to consumers and passing on a share of cost savings, where relevant. If consumers are providing a beneficial service to EDBs, it is reasonable that they should be rewarded for this.

Whilst we understand what the ECTF is trying to achieve with the rebates proposed under the 2a paper, even if the approximate $12 per annum per ICP rebate from EDBs were to be passed directly to consumers via retailers, it is unlikely such a sum or price signal would materially shift consumer behaviours. Moreover, from some existing discussions, some retailers have indicated they are unlikely to pass on these rebates directly to the specific consumer generating that benefit.

We also think it is important that regulation doesn't have unintended consequences that stifle demand and innovation from flexibility providers and aggregators. Export at peak by individual households is likely to be inconsistent and unreliable. We note that the ECTF still feels there is a "significant role" for aggregators, but we urge caution against regulations that hamstring the

---

[6] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 13, paragraph 4.6

[7] Electricity Authority, Transmission Pricing Methodology - Decision Paper, 2022, page 41, paragraph 5.54(c) which states "the Authority's consistent view that generators should pay for the benefit they receive"

[8] Electricity Authority, Distributed generation pricing principles, 12 February 2025, section 2

[9] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 15, paragraph 5.2

development of this market, which is likely to provide better network benefits than ad hoc individual household exports. We look forward to seeing the guidance proposed to consider this.[10]

2.4 Principles are more enduring in times of change

Given the evolving nature of export tariffs and current implementation challenges, we support the ECTF and Authority's proposals in all three papers for a principles-based approach. As noted in the DGPP paper, a "one-size-fits-all prescription may not suit all circumstances"[11] and principles allow flexibility. They "will allow distributors to respond most effectively to the circumstances and adapt their approach over time, as more information (including more granular data on network costs) becomes available."[12]

We also advocate for these principles to sit outside of the Code, as this will allow for easier and more flexible amendment by the Authority in due course, if required.

2.5 Access to data

To help ensure that networks continue to meet consumers' needs for reliability and stability, improved visibility of low-voltage networks will be critical to successful network transformation.

If EDBs had access to reliable and reasonably priced smart meter data, they could better understand household electricity demand and plan and operate the electricity network more accurately, which would save customers money.

Data is also needed to set the prices and calculate more accurate rebates under the 2a recommendations. There is a risk that the 2a rebates will result in high level estimates being used in place of EDBs being able to accurately calculate network benefits, which may increase the risk of wealth transfer and/or over-incentivising exports at peak. Price signals can be more accurately targeted with the right data.

ENA thanks the Authority for including the requirement for retailers to provide half-hourly data to distributors as part of the 2bc recommendations. It has sometimes been difficult for EDBs to acquire this information from retailers. However, experience has shown that this data is not always complete or accurate. ENA therefore has some concerns about the 12A.4 requirement that this data "must" be used by EDBs to calculate charges.

2.6 Targeted interventions and consistent regulatory approaches

We are concerned that the ECTF and the Authority are too unfocused with their proposed regulatory interventions and are not appropriately prioritising interventions in line with where the most material impacts will be.

Regulatory overload is affecting many parts of the sector, and its impact is continually ignored by the Authority. The sector doesn't have the resources or capacity to handle so many concurrent requirements, all on similar timelines, whilst also trying to run the daily operations of the business

[10] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 22-23, paragraphs 5.19-5.22

[11] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 13, paragraph 2.29

[12] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 21, paragraph 3.37

and serve our customers. It seems that everything coming from the Authority and the ECTF is 'urgent' and 'significant', when in reality, in many cases, the proposals are neither.

The 2a paper, for example, is unlikely to have a material impact on consumer bills or change consumer behaviour. Time varying price plans are also already widely available in the market, so the 2bc paper proposals are also unlikely to have a material impact on consumer behaviours.

There is also an inconsistency in the approaches being applied by the Authority, particularly in relation to pricing principles. It would be far more efficient and effective to apply a more consistent set of pricing principles, rather than issuing multiple different sets of principles, some of which appear to openly contradict each other.

The DGPP issues paper refers to, for example, the disadvantages of formulaic approaches, how guidance could be provided outside of the Code and there are several examples in section 2 that seem to contradict similar matters identified in the load connections proposals from last year.

The Authority's 'tinkering' with the Code also leads to confusion and inconsistent application. Urgency over quality results in Code amendment proposals such as the 2ab paper proposal for 12A.4, which states that "despite anything else in this Code or in a distributor agreement, distributors must…"[13] That is a very confusing drafting approach. For example, if you turn to the 'other' 'overridden' sections of the Code first, how do you know that section has been subsequently overridden by this clause? The Code needs a thorough tidy up and cull to ensure it meets good regulatory practice, especially in relation to regulations needing to be "easy to find, easy to navigate, and clear and easy to understand."[14]

ENA submits that to meaningfully address Aotearoa's energy system challenges, the Task Force should prioritise initiatives that can truly move the dial on security of supply and affordability. The current proposals, while well-intentioned, risk implementing complex requirements with questionable benefits – for both consumers and distributors. While these initiatives may have merit in their own right, they should be positioned as complementary to, not substitutes for, more direct interventions in the wholesale market, and should not be the priorities of the Task Force right now.

2.7 Feedback on specific proposals

A summary of the key views and recommendations for each proposal is set out in Table 1 below. Section 3 of this submission outlines the key themes and considerations supporting these views and recommendations. We provide answers to the ECTF and Authority's specific consultation questions in Appendices B, C and D for each consultation paper in turn.

[13] Energy Competition Task Force, Improving pricing plan options for consumers,12 February 2025, page 64
[14] Treasury, Government Expectations for Good Regulatory Practice, April 2017, page 4

Table 1: Summary of ENA feedback on ECTF and Authority proposals

PROPOSAL	SUMMARY OF KEY ENA VIEWS	RECOMMENDATIONS
Requiring distributors to pay a rebate when consumers supply electricity at peak times	- ENA supports the underlying principle that where generation is reducing network costs, this is recognised. - We appreciate the pragmatic principles-based approach the ECTF has taken. - We support providing consumers with more options. - As noted in the paper, not all exports generate cost benefits to networks and failure to target rebates appropriately will result in higher costs for all consumers. - We agree that well-managed flexible distributed generation is likely to generate cost savings across the system in the long-term, but note that there will likely be increased costs in the short-term to develop better management of 2-way electricity flows. - As the flexibility market evolves, more sophisticated arrangements are likely to emerge, these rebates could act as barriers to aggregators and other flexibility providers.	- We don't think the 2a proposals are likely to have the desired impacts and question whether they are worth proceeding with. However, assuming the ECTF will proceed with them, we recommend that the principle that rebates only be paid consistent with distribution pricing principles where there are network benefits be retained. - We also recommend a similar approach to the 2bc proposal with a sunset clause or implementing the proposal on a trial basis. At a minimum, the Authority should commit to a mandatory review of the changes after a few years to ensure they are generating the expected benefits, aren't curtailing innovation and competition within demand flexibility and are fit for purpose. - The ECTF may want to be cautious with market information regarding these changes as, based on some media coverage in recent weeks, false expectations may be being created around the scale of the impact on consumers.

PROPOSAL	SUMMARY OF KEY ENA VIEWS	RECOMMENDATIONS
Improving pricing plan options for consumers – time-varying retail pricing for electricity consumption and supply	- We support providing consumers with more options - We agree that the provision by retailers of consumption and injection data to distributors is necessary for the effective implementation of the proposals. However, we are concerned that the requirements, as written, may reduce the level of data already provided by some retailers. - We have concerns about the 12A.4 drafting and its unintended consequences, both in terms of the confusion caused by applying this as an override clause and also forcing this data to be used, when sometimes it is inaccurate and incomplete. - We acknowledge that the retail sector is a competitive market and are concerned that applying regulation to only some participants will negatively impact on competition and unevenly impact EDBs. - We are unsure that mandating that all retailers offer TOU plans will have the expected impact of moving more consumers onto these plans. There are already many time-varying plans in the market should consumers wish to be on such plans.	- Further develop mechanisms to support access to meter data for distributors. - Recommend changing wording of 00.4 to stipulate that retailers must supply '*at least* half-hourly data to distributors, where available.' - We recommend removing clause 12A.4 from the Code amendments. - We recommend that the 2ab proposals be applied to all retailers or not at all, to maintain a level playing field between participants.

PROPOSAL	SUMMARY OF KEY ENA VIEWS	RECOMMENDATIONS
Distributed generation pricing principles	- ENA is aware that the DGPP are influencing EDBs investment and pricing decisions, and may not be delivering efficient outcomes. As a result there is a need to review the DGPPs to ensure they are fit for purpose. - It is, however, difficult to express a strong preference on the options given the paper doesn't define how the DGPPs would be revised under the proposals – the devil is always in the detail. - In principle, we agree with Option 4 to comprehensively overhaul the DGPP. However, we are concerned that in one breath the Authority says that option 4's overhauls would result in less prescriptive new principles[15] and in another breath, the Authority suggests that similar principles to the connection pricing proposals from last year could be applied.[16] These are quite contrary alternatives and could result in very different outcomes for EDBs. - Whilst ENA supports option 4, it might be more reflective to say we support a comprehensive review of the current DGPPs, but consider that the Authority should keep an open mind with regards to the outcomes of that review.	- We recommend that the Authority apply more consistency across the various workstreams looking at distribution pricing principles, including connection pricing and distributed generation. - Many of the arguments in the DGPP issues paper are equally relevant to connection pricing and we suggest the connection pricing team review this issues paper as well prior to making any decisions. - Given the lack of certainty and detail within the issues paper, we recommend that comprehensive engagement with EDBs and other stakeholders be undertaken in the development of the next consultation.

[15] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 19, paragraph 3.26
[16] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 19, paragraph 3.29

3 Key themes and interdependencies

This section sets out ENA's views on the key themes and interdependencies between the three consultations set out in Section 1 in more detail.

3.1 Empowering and rewarding consumers

3.1.1 Support empowering consumers to make informed choices

Consumers should have choice to decide whether or not they sign up to time-varying pricing plans, or how to respond to pricing signals more generally. With that choice, consumers should be fairly rewarded for benefits they bring to the system as well.

Consumers should also have a choice as to how and when they sell their surplus power. Regulations should not restrict this choice. We urge the ECTF to apply caution to how the 2bc paper proposals may impact on this choice. For example, it should be ensured that mandating retailers to provide time-varying buy-back plans does not prevent customers from separating their consumption and export plans and contracting with multiple traders, aggregators or other providers. Consumers should also not be prohibited from being compensated for their load-shifting or injection via non-financial incentives, if that is their preference.

3.1.2 Not all exports generate network benefits

As acknowledged in the paper, whilst there is great potential for benefits through DG, "injection can either reduce or add to network costs depending on the time and location of the injection."[17]

Several EDBs have desktop reviews or real-world experience demonstrating that DG doesn't generate cost-saving benefits on their networks. Even if the injection occurs at consumption peaks, if the network isn't congested, "the injection is unlikely to incur or reduce any network costs."[18]

EDBs have no control over the amount of DG they receive, the timing of the injection or the consistency of the injection. If injection is too intermittent, EDBs cannot rely on receiving it and need to invest in the network to ensure their services are maintained. Whilst price signals may help with this, they will only go so far. Many household DG setups would be predominantly used for self-consumption and will have limited capacity to export.

For networks, the benefit of batteries tends to come more from a reduction in consumption rather than the export value of surplus power.

There is also a risk that EDBs end up paying twice if insufficient injection is received. For example, if you have 5 ICPs injecting in a constrained area and you reward these DG customers for helping to alleviate the constraint, but you actually need injection from 100 ICPs to be able to defer or avoid network investment, then you pay for both the rebate and the network investment (i.e. the network investment has to occur regardless of the injection). This would increase overall network costs, which would, in turn, increase costs for consumers.

[17] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 13, paragraph 4.6

[18] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 13, paragraph 4.6(c)

EDBs also have an obligation to provide access to their networks, including connections and reasonable capacity. Until such time as DG customers contract out of such an arrangement or go fully off grid, EDBs need to continue to invest in networks to maintain capacity to be able to provide power to consumers, even if they have DG. Solar is not a stable and reliable power source, although batteries can help mitigate against periods of non-generation.

There is also an established precedent that generation/ export should also pay for networks and not 'free ride',[19] a point emphasised in the DGPP issues paper.[20] "The Authority's consistent view that generators should pay for the benefit they receive."[21] This may lead to charges rather than rebates for DG customers.

In light of the above considerations, ENA thinks the 2a paper Code amendment, as proposed, is well calibrated to mitigate these risks. To avoid increasing network costs and causing wealth transfers from non-DG consumers to DG consumers, it is essential that the "at times when the injection provides network benefits"[22] clause is retained in the final decision.

It would be helpful for the Authority to clarify in its final decision that export pricing should be consistent with demand/ consumption pricing for any region or connection within it, and so consistent with the Authority's distribution pricing principles.[23]

3.1.3 Peak versus congestion

Whilst times of peak demand are the best proxy for simplified signals of network constraint (in the absence of detailed network data), networks are not necessarily constrained at peak times and are not necessarily constrained in all areas at all peak times.

Congested areas are also not static. Engineers reconfigure the network to address peaks and this moves customers in and out of the congested areas. Times of peak congestion can also differ depending on whether you are considering low, medium or high voltage sections of the network.

Therefore, it can be difficult to accurately predict which areas of the network will benefit from peak injection by consumers. Having the right data to support an approach is key, as discussed further below.

However, we note that whilst the 2a paper's title suggests a rebate is payable when DG customers inject "at peak times", the Code amendment is not so prescriptive. We support this flexibility in proposed the Code wording. "At times when the injection provides network benefits"[24] allows for EDBs to tailor their offerings based on their own network configurations and impacts, as well as the level of data they have available on which to base calculations.

To comply with the proposed 2a amendments, some EDBs may apply across all peak consumption periods, or all winter peaks, for simplicity. Some may attempt more complex calculations to target network-benefit areas. There is a trade-off between accuracy and simplicity. This may result in export

[19] Electricity Authority, Transmission Pricing Methodology - Decision Paper, 2022, page 41, paragraph 5.54(c)
[20] Electricity Authority, Distributed generation pricing principles, 12 February 2025, section 2
[21] Electricity Authority, Transmission Pricing Methodology - Decision Paper, 2022, page 41, paragraph 5.54(c)
[22] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 44, clause (1)(b)(i)
[23] By this, we mean that the distribution pricing principles and associated practice note do not require consumption pricing at a set locational or granular level, but rather at the most appropriate level for the EDB and its customers. It is our understanding and expectation that the 2a paper is not proposing that export rebates need to be calculated at a level of granularity and detail in excess of the consumption requirements outlined in the pricing principles and associated guidance. It would be helpful if the Authority confirmed this in its final decision, guidance and any FAQ responses associated with this consultation.
[24] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 44, clause (1)(b)(i)

rebates that are not fully cost-reflective and there may be some wealth transfer impacts. However, this is hopefully minimised.

3.1.4 Prescribed rates

The variability of impacts noted above is a clear reason why ENA supports the ECTF's conclusion that prescriptive rates are not a good alternative:

> *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.*[25]

3.1.5 Asymmetrical tariffs

Equally, while we support the idea of symmetrical tariffs in theory, there are several reasons why we don't think these are appropriate at this time. For now, in addition to the points noted in the 2a paper, we believe export rebates should be lower than consumption tariffs for the following reasons:

- To encourage households to offset their own demand before exporting surplus energy, including preventing 'battery dumping' at the start of congestion periods. We have seen evidence, for example, of consumers over-exporting at a peak and then finding by the end of the peak that they need to consume from the network, resulting in a net cost to the consumer.
- To reflect that consumption tariffs can include other costs such as use-of-system changes, maintenance and business support. Generation does not reduce these costs, so should not be paid a rate that includes these.
- To limit risk, should enough injection occur at times that is not helpful to networks, which may end up creating costs rather than benefits (as is currently happening in some parts of Australia).
- To acknowledge the value of aggregation and flexibility providers, which is discussed further below.

As the Authority states, "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."[26]

3.1.6 Locational-based pricing

The 2a paper proposals are akin to locational-based pricing. Whilst locational pricing could provide more accurate price signals, promoting more efficient use of the network, it also adds a layer of complexity for all parties.

Distributors, retailers and consumers would be impacted. Implementing highly granular locational pricing at the retail level could lead to confusion among consumers, especially if charges vary significantly within small geographic areas, potentially undermining consumer confidence. There are

---

[25] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 25, paragraph 5.31
[26] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 27, paragraph 5.39(b)

examples of EDBs trialling more innovative pricing in specific constrained areas, where consumers in nearby unconstrained areas expressed concerns about why they couldn't access the same pricing.

3.1.7 Time of use

Consumption

Many acknowledge that changing consumption behaviour (including their own) can be difficult to achieve in practice. Only a certain amount of daily consumption can be shifted. Generally, activities like cooking, showering, heating and air conditioning are used when needed, not necessarily when it is cheapest. Only things like running the dishwasher or delay timers for laundry are likely to be able to be shifted fairly easily, along with the increasing relevance of EV charging overnight. According to an Australian study, washing machines and dishwashers "would likely account for no more than 10% of home energy usage. This indicates the financial benefits of time-of-use tariffs are likely modest for many households."[27]

As noted in the 2a paper, "consumption price signals provide a nudge towards beneficial investment and behavioural decisions, but consumption is still largely influenced by habit and necessity."[28]

Moreover, the Australian study also suggested that "lower income households were more likely to say they were changing when they used heating and cooling to save money. This is potentially worrying, given the importance of keeping homes at a comfortable temperature for health benefits."[29]

TOU is not by default considered cost-reflective, as 'cost-reflective pricing' is the setting of prices to recover the economic costs of electricity distribution services. Prices are cost-reflective when they reflect the underlying drivers (i.e., causes) of the costs to serve. TOU pricing is effective when a distributor can demonstrate an existing or emerging constraint on the network driven by consumer behaviour. For example, a rapidly growing EV penetration causes a sharp and unsustained peak in an area of a distributor's network. TOU prices can be 'inefficient' when prices are not reflective of existing or emerging network constraints. Inefficient prices can have unintended consequences, such as shifting the peaks instead of reducing demand during the peaks.

Consumer and retailer engagement, both in New Zealand and overseas, shows there are mixed views on the appeal of TOU pricing. There are TOU price plans in the market already, as well as export-related tariffs for DG customers. Do such plans need to be provided and advertised by all retailers or should it be about retailer discretion and relying on the competitive market to address consumer demands? We think it should be the latter.

We note that the ECTF does express a desire for retailers to continue to be free to innovate, including on price. However, ENA is not clear why the ECTF feels that regulation is required to mandate provision of TOU plans, and only to a subset of the retail market. TOU plans are already provided by a subset of retailers. If this meets the need of consumers, then they will take it up, provided they are aware of the option. So, why now mandate TOU for a different subset of retailers?

Buy-back/ export

As noted in relation to consumer impacts from 2a proposals, unless they are highly concentrated by location and within time periods, network price signals in relation to exporting surplus DG are likely

[27] Energy Consumer Australia, Consumer Energy Report Card: Consumer knowledge of electricity pricing and responsiveness to price signals, 16 January 2025, accessed 20 March 2025

[28] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 27, paragraph 5.39(b)

[29] Energy Consumer Australia, Consumer Energy Report Card: Consumer knowledge of electricity pricing and responsiveness to price signals, 16 January 2025, accessed 20 March 2025

to be small as compared to the impacts from wholesale/spot price impacts. It seems reasonable that buy-back rates should reflect the benefits they bring to retailers (the 2bc paper proposals), in the same way as the proposals under 2a are designed to reflect time and locational network benefits.

As noted above, it should be ensured that mandating retailers to provide time-varying buy-back plans does not prevent a consumer from separating their consumption and export plans and contracting with multiple traders, aggregators or other providers. It should also not prevent consumers from choosing to realise their benefits via other, non-monetary incentives, if that is their preference.

Consistency of peaks

It should be noted that peaks definitions by retailers may vary to those of networks, in the same way that peaks within networks can vary by time of year or region. Whilst we are not necessarily suggesting this is an issue with the 2bc proposal, we think it may influence the effectiveness of mandatory TOU implementation by retailers.

Alternatives to mandated TOU

TOU is also not the only way to influence peak demand. Existing, and growing, areas of demand response, such as hot water and EV load controls, may be more effective measures than mandating TOU. Retailers are rapidly building the capability and scale to manage consumer load directly, especially hot water, facilitated by metering equipment providers (MEPs).

It could also be argued that the Authority is trying to mandate TOU because they believe current switching arrangements are not effective. With many TOU pricing plans available for consumers in the market already, one could suggest that if consumers wanted TOU, they would switch to a provider that offers it.

With an upcoming consultation on switching expected imminently, we are also hopeful that the changes proposed by 2bc maintain their proposed value. As noted in the section below on regulatory interventions, there is a risk that multiple concurrent reforms could add confusion and counteract each other's value.

3.1.8 Ensuring price signals reach consumers

The price signal (positive or negative) that the final customer ultimately observes depends entirely on the extent to which retailers 'pass-through' any rebates. Whilst ENA recognises the primacy of a retailer's role in attracting customers by offering prices or alternative incentives that appeal to them, with very marginal price signals likely to result from the 2a paper proposals (less than $12 per customer per year), any dilution through retailers is likely to weaken the distribution signal and may result in no consumer response, and therefore no distribution benefits being realised.

A worst-case scenario from the 2a proposals is that EDBs calculate and offer rebates on the basis that exports will create network benefits, but that these rebates get absorbed by retailers without any shift in consumer/DG behaviour to generate the expected network benefits on which the rebate was based. This could result in a net increase in EDB costs (paying for the rebates for expected benefits, implementation and administration costs of the scheme, and the investment that was not able to be avoided or deferred due to benefits not being realised) and therefore higher costs to consumers.

ENA recognises that distribution pricing signals are only one element of a retailers' input costs. It is the retailers' role to set consumer prices and other incentives in a manner that considers the input costs, consumer demand and consumer preferences.

However, if retailer or consumer feedback doesn't support time-varying buy-backs and/or the 2bc paper proposals for time varying buy-back do not proceed as currently indicated, the ECTF should consider the potential impacts of continuing to pursue the 2a proposals in isolation.

In the meantime, we must assume that there is enough competition and benefit to consumers that EDB price signals will incentivise appropriate rewards to be offered to consumers by retailers. If this does not happen, then the 2a principles, as currently proposed, should provide enough scope to adjust pricing in future price periods to reflect the 'real' benefit being received.

On the subject of whether or not to mandate that retailers pass-through EDB price signals – in this case, in the form of peak export rebates - ENA members hold a range of different views and there is no clear consensus position. Some strongly believe retailers should have independence to design their own pricing. Others have concerns that if retailers do not transparently pass through EDB price signals, then the desired consumer behaviour will not be elicited. ENA therefore refers the Authority and ECTF to individual EDB submissions for a more nuanced understanding of the sector's views on this subject.

3.1.9 Provide consistency in signals

Some exports at times or locations "may contribute to additional investment requirements."[30] The impact of this has already been seen in Australia, with two-way pricing coming into effect this year, with some having already trialled this earlier. There is therefore a risk that rebates are offered now, but in a few years, these switch to charges. This sends an inconsistent message to DG.

One principle of pricing is to have consistent and long-lasting pricing so that consumers can invest knowing they will be rewarded for their investment. We encourage the Authority and ECTF to keep this in mind when developing pricing proposals.

3.1.10 Promotion, consumer awareness and moderating expectations

2a proposals are not really new

We note that the existing DGPP already requires distributors to "include consideration of any identifiable avoided or avoidable costs."[31] So if there had been identifiable avoided or avoidable costs (i.e. network benefits), EDBs would already have been required to recognise these within pricing. It is perhaps therefore not surprising that the expected impacts from the 2a proposals are only to provide rebates of <$1 per month per customer.

Price signals may not reach consumers

Before these ECTF proposals, some EDBs have been exploring rebates as an option and have found when consulting with retailers, that some have said they won't pass on the rebate price signals. This may mean that DG export behaviour may not shift and may not deliver anticipated network benefits.

Fairly represent consumer impacts of 2a rebates

The proposed 2a rebates are of very low value relative to the investment required in solar and battery systems. So, whilst the principle of rewarding customers for the benefits they bring to networks is

[30] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 13, paragraph 4.6 (b)
[31] Electricity Authority, The Code, Clause 2 of Schedule 6.4

important, we also think it's clear that the 2a rebates are not going to influence a consumer's decision as to whether or not to invest in a solar and battery system.

The Task Force's own analysis indicates that residential consumers would receive minimal monthly rebates ($0.00 – $0.72). Given that residential consumer solar and battery systems typically range from $22,000 to $37,000 or more, these rebates are insufficient to meaningfully influence investment decisions or drive the intended system network benefits.

The benefits of solar and battery systems are more in the savings they make from self-consumption, with export earnings as a secondary benefit. Moreover, it is more likely that retail price signals will have a more material impact on export tariffs, as this is where wholesale/ spot price impacts will be more reflected.

We therefore think it important that the Authority and ECTF are careful in how these 2a proposals (and ultimately decisions) are framed in the media. When the papers were published in February, the media coverage risked raising expectations that much higher returns would be generated for consumers than is actually the case, as outlined in Appendix A of the 2a paper.

Ensuring consumers are informed of their choices

ENA supports improving transparency by requiring electricity providers to promote their plans, display time-of-use and other plans on their websites, list all plans on Powerswitch, and offer beneficial plans proactively. However, we are not sure it is necessary for regulators to determine how often retailers should present their offers.

Accepting consumer behaviour may not do what the Authority wants

Behind the 2a, 2b and 2c proposals is a desire to influence and shift consumer behaviour. However, even with significant price signals, consumers do not always respond to signals and not all consumer behaviour is 'economically rational'.

ENA supports providing reasonable, cost-reflective incentives to guide consumer choice and encourage certain behaviours. However, it is equally important to recognise that consumers may choose not to adjust their behaviour—and that's okay. As long as they are well-informed, their decision to disregard incentives should not be seen as a failure of the pricing policies.

Have the ECTF or the Authority consulted with consumers and flex providers about what they want and what their blockers are? Has this been factored into the ECTF and Authority priorities and proposals? If so, it is not clear from the consultation documents.

Many consumers already think bills are confusing and moving to complex pricing is unlikely to help with that problem. Studies in Australia have suggested that consumers generally prefer simple retail pricing options. That said, those that were more "interested in having greater control, choice or flexibility over how they use and manage their energy consumption… were more likely to be higher income homeowner households with existing solar systems."[32]

3.1.11 Impact of and on aggregators and flex providers

The ECTF and the Authority should ensure that regulations, including those relating to the 2a, 2b and 2c initiatives, do not hinder consumers' ability to choose who to sell their surplus power to, fostering competition and potentially improving returns.

[32] Energy Consumer Australia, Consumer Energy Report Card: Consumer knowledge of electricity pricing and responsiveness to price signals, 16 January 2025, accessed 20 March 2025

Certain arrangements, such as via flexibility providers and aggregators are also likely to maximise benefits to networks. With individual households independently exporting, exports are likely to be small, unpredictable and therefore offer limited benefits to networks.

Aggregators and flex providers on the other hand can coordinate exports across many sites. They can control when and how much energy is exported, reducing network strain and optimising for network needs.

We acknowledge that the 2a paper suggests that where aggregator benefits outweigh direct customer rebates, then the EDBs should continue to work with aggregators and not pay additional rebates. However, we believe there is a non-trivial risk that the proposed 2a rebates could discourage investment in demand-side management by aggregators.

It appears as if the ECTF is perhaps sidestepping this by arguing that if customers are already paid by an aggregator, an export rebate would be unnecessary – implying coexistence is possible.[33] But is that the right framing? Given that aggregation is still relatively new in New Zealand, the more likely scenario is the reverse: customers would already be receiving export rebates, which could crowd out future aggregator investment.

If customers are already capturing some (or too much) value from rebates, there may be little room left for additional flexibility services, even if aggregators could add value. If the expectation is that rebates will be used sparingly to avoid cost increases, would it not be better to let distributors and aggregators contract directly with flexibility providers rather than introducing these rebates at all? We think this is something the ECTF should consider.

As noted in the context of consumer choice above, we also encourage the ECTF and the Authority to be careful not to hinder consumer choice in how they sell surplus power, and how they choose to be rewarded for it. Allowing consumers to contract with multiple electricity suppliers and aggregators fosters a more competitive environment, where service providers must offer better prices and services to attract and retain customers.

We recommend that the ECTF and the Authority clarify the policy intent and drafting of these proposals to distinguish between prices and tendered flexibility. The former is about signalling the long-run marginal costs of planned investment through regional peaks, the latter is about deferring individual projects – which means they can coexist efficiently. It will be important to engage directly with flexibility stakeholders and mass market consumers to better understand and identify the signals they need to install solar/DG for these two purposes.

3.2 Change management

In this section we address matters relating to the more practical implications of the proposals.

3.2.1 Terminology

The terminology used can have real-world implications for EDBs, consumers, and other stakeholders.

Whilst ‘rebate’ and ‘negative tariff’ may both have the same impact on consumers paying less (on a net basis), they have different tax, accounting and regulatory treatments.

A ‘rebate’ is usually seen as a ‘refund’ or ‘return of part of a payment’ already made by the customer. A rebate typically reduces revenue for the company providing it.

[33] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 22-23, paragraphs 5.19-5.22

For GST, a 'rebate' can reduce the consideration for the supply. This may require GST adjustments and credit notes (you might need to adjust the GST amount because the value of the supply has changed).

On the other hand, a 'negative tariff' is often framed as a 'payment' to a customer. Instead of being a refund, it's treated as an income the customer earns by providing a service. In this context, the EDBs would record that as an operating expense.

If the customer (say, a household solar generator) is registered for GST, the negative tariff payment might be subject to GST—because it's treated as a supply of goods/services (they're providing energy or flexibility). It is likely to affect commercial participants or larger generators more than households, but theoretically it could apply to anyone registered for GST (note that the GST registration threshold is $60k turnover per year).

Using 'rebate' suggests the consumer is getting some money back from what they already paid—so it's a price reduction, not a new transaction. Given the nature of the 2a paper and time-varying buy-back component on the 2bc paper, arguably the term 'negative tariff' would be more appropriate, as it suggests the consumer is getting paid for a service.

We recommend that the ECTF receives tax and accounting advice in relation to this matter to ensure the most appropriate outcomes for stakeholders.

3.2.2 Interdependencies with Part 4

Terminology and treatment

Amongst other things, the framing and terminology used in the final decisions will impact on the regulatory treatment of the amendments. The distinction between 'rebates' and 'negative tariffs' isn't just a tax and accounting issue—it has direct implications for how these payments are treated under the Commerce Commission's (the Commission) regulatory framework, especially under the Default Price-Quality Path (DPP).

'Rebates' reduce 'allowable revenue' or 'price' under the price path. If an EDB provides a rebate, it effectively lowers their recorded revenue, which:

- Impacts compliance with the price-quality path because regulated revenue is assessed net of rebates.
- Affects future price path resets, as historical revenue and expenditure patterns can influence building block calculations.

A 'negative tariff' is more like a payment for a service. It is generally treated as an operating expense (opex), rather than a reduction in revenue. It is possible that the costs related to a 'negative tariff' – paying customers for exporting surplus power at peak times - could also be justified as a non-network solution.

We would appreciate if the final decision directly addressed this matter, especially since these proposals have come from the joint Electricity Authority and Commerce Commission ECTF. This would provide greater clarity on how the proposed amendments will be treated from a regulatory perspective.

DPP4 determination and timing of new proposals

It is worth noting that the DPP4 decision (made on 20 November 2024) has created constraints on some networks. Those networks are still reviewing and reprioritising their expenditure for DPP4 in order to fit within the Commission's allowances. Some EDBs also attempt to limit consumer price shocks (beyond the smoothing mechanisms employed by the Commission) and so don't make large changes to pricing in one go.

These constrained EDBs, in particular, cannot pay a rebate for DG where it is not deferring planned capex or providing a network benefit. This is one of many good reasons for retaining within the final 2a principles the requirement for rebates to only be required where there are network benefits.

Changes to pricing principles

ENA recommends that careful consideration is given to the contractual arrangements that exist currently between DG and EDBs so that removal of DGPP does not leave EDBs with material costs that could not be recovered through the Input Methodologies.

Overlapping requirements

Please refer to section 3.4.1 below for a discussion of how the proposed changes to DGPPs may indicate the Authority overreaching and seeking regulation to incentivise behaviours that are already being incentivised through the Commission regime.

3.2.3 Timeframes

Good regulatory practice

As stated in the Treasury's guidance on good regulatory practice:

> *Before a substantive regulatory change is formally made, the government expects regulatory agencies to:*
>
> - *allow regulated parties reasonable time to get familiar with new requirements before the change comes into force (unless this would compromise the outcome sought)*
> - *test key operational processes required to implement the change*
> - *anticipate and plan for the possibility of unintended consequences or the potential need for contingency measures, and*
> - *provide for any appropriate changes to system monitoring arrangements.*[34]

There is also an expectation that regulators "provide accessible, timely information and support to help regulated parties understand and meet their regulatory obligations."[35]

Urgency versus materiality

Whilst we understand the Authority's desire to move quickly with new regulations, we question whether everything needs to be done at pace.

As noted in the 2a paper, "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."[36] Despite that, "the Authority expects the implementation costs of the proposal to be relatively minor."[37] Whilst that may be true, with an estimated benefit of only about 72 cents per customer per year, one does

[34] Treasury, Government Expectations for Good Regulatory Practice, April 2017, page 6
[35] Treasury, Government Expectations for Good Regulatory Practice, April 2017, page 7
[36] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 2
[37] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 31, paragraph 6.14

question whether “the benefits of the proposal will significantly exceed the costs and potential risks.”[38]

According to data from the Authority, at the end of February 2025, there were 9,143 installed solar systems with batteries (the most likely beneficiaries under the 2a paper proposals), with a total capacity of 61.5MW.[39] At 72 cents per customer per month, that would be less than $80,000 total rebate value per year (assuming all those ICPs contribute to network benefits).

Does an intervention of this scale and low consumer impact, targeting such a small subset (0.4%) of the approximately 2.3 million ICPs in New Zealand, really meet the ECTF criteria or justify the so-called “urgent need to provide consumers with more options to manage their energy bills”[40]? We don’t think that it does.

Does moving the dial on retailer TOU offerings, when the regulations as currently proposed are only likely to change the behaviour of 2 of over 60 retailers? We don’t think that it does.

We have seen several other examples in recent months of the Authority ‘rushing’ decision-making and implementation timeframes in unrealistic ways, often with negative consequences for the stakeholders involved. We discuss the principles and impacts of this further in the section on ‘Focused regulatory interventions’ below. In this section, we focus more on the practical implementation challenges of these fast-paced interventions.

Timeframes may be unrealistic for some EDBs and retailers

We appreciate the Authority’s motivation in pushing hard for change. ENA members are also wanting progress - but on a least-regrets basis to avoid alienating stakeholders including retailers, unduly upsetting consumers, and avoiding or reducing the potential for politicisation of change. Speed of change is important, but less so than identification of durable, stable solutions that are broadly publicly acceptable and capable of being acted on by consumers. There are well-recognised examples of pricing reforms that have gone awry, attracting undue political attention that has then resulted in interventions that have hindered reform.

EDBs are at different stages of maturity and have different levels of data access (a point discussed further below). They have different tools and expertise in place to calculate avoidable costs and network benefits for different parts of their networks. EDBs are also very different in size, with each organisation having different capacities to deliver meaningful outputs (e.g. time and effort to update systems and processes).

The current proposals are also not occurring in isolation. In addition to the ‘business as usual’ of operating the networks, some EDBs are also working through challenging DPP4 implementations and reprioritisations. On top of that, the constant stream of new initiatives and amendments from the Authority maintain a constant pipeline/backlog of issues to understand and decisions to implement. Each individual decision may look small in isolation, but it would be appreciated if the Authority could consider the bigger picture of what is being asked of EDBs (and other market participants).

As a result, a ‘one size fits all’ timeframe for having this in place is unlikely to be achievable for all EDBs and could lead to rushed or poor outcomes. We expect this will be drawn out further in individual EDB submissions on the proposals. ENA also understands that this is not an issue unique to EDBs, but is affecting many other market participants too, including retailers.

[38] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 32, paragraph 6.18
[39] Electricity Authority, Electricity Authority - EMI (market statistics and tools), ‘Installed distributed generation trends’ dashboard, filtered by fuel type ‘solar (with battery)’, accessed 20 March 2025
[40] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 19, paragraph 5.12

ENA still has concerns about the Authority's expectations around 'signalling' when it comes to implementing change. We understand that the Authority often believes it has 'signalled' changes or the 'direction of travel' in advance, whilst proposals are still subject to consultation. However, it is unreasonable and is poor practice to expect stakeholders to make changes until decisions have been finalised.

Assuming implementation timeframes can be reduced due to previous 'signalling' runs the risk of either assuming Authority outcomes are pre-determined or implying that the Authority expects participants to be making speculative investments and changes, which is unlikely to be in the best interests of consumers and affordability.

Timeframes for decisions and guidance

We note that the 2a paper and DGPP issues paper both refer to the Authority publishing further guidance (outside the Code) on how the principles should be considered in practice.[41] [42]

We support the provision of further guidance to assist with the implementation of the proposed changes and we support the ECTF's proposal to seek feedback on that guidance.

Guidance is designed to support implementation and assist with any interpretation issues. It is a key input for participants into their solution design and overall change management processes. It is reasonable to expect that EDBs do not undertake significant investment into implementing the proposed changes until this guidance is issued. To do so would risk increasing costs to consumers through unnecessary rework should the guidance recommend alternative approaches.

We note, for example, that the guidance for retailers to implement their consumer care obligations was released on 19 March, ahead of the 1 April implementation deadline.[43] This is not an example of 'good regulatory practice' and seems to further suggest that implementation deadlines are unrealistic, even for the Authority themselves.

The ECTF and the Authority should ensure that any decision for which guidance is required allows for this step in the implementation timeframes.

Clarity of implementation timelines within the annual pricing cycle

Whilst we appreciate the ECTF's acknowledgement "that distributors have to comply with Commission rules around Information Disclosure (ID) that mandate certain times and processes around changes to pricing methodologies"[44], we are concerned that this is at odds with framing of the proposed amendment timings. The ECTF states: "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."[45]

By contrast, our understanding is that if the Authority sets an effective date for the Code change of 1 April 2026, then it can only impact pricing methodologies that are set on or after 1 April 2026. Pricing methodologies must be disclosed before the start of each disclosure year (before 1 April 2026, or 20

[41] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 16, paragraph 5.7

[42] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 20, paragraph 3.33

[43] Electricity Authority, https://www.ea.govt.nz/news/general-news/guidance-for-retailers-to-implement-all-consumer-care-obligations-from-1-april/, 19 March 2025

[44] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 32, paragraph 6.17

[45] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 19, paragraph 5.11

business days earlier if there is a change to the methodology, such as would be required for DG payments. Under the default distributor agreement (DDA), EDBs are also required to notify retailers of price changes 40 working days before they come into effect.

As a result, when EDBs disclose the pricing methodologies (under 2.4.1 of the Information Disclosures) on or before 31 March 2026, they would be compliant with the existing Code, as the proposed changes would not yet be in force.

The Code would come into force on 1 April 2026, meaning pricing methodologies published after 1 April 2026 and on or before 31 March 2027 would be subject to the new rules. The changes would therefore apply in practice for the 2027/2028 pricing year.

Consultation requirements

It is also a requirement under the DDA that EDBs must consult with traders before implementing changes to pricing structures. Implementation timelines should ensure the time required for this consultation requirement is also taken into account.

3.2.4 Consistency between retailer and distributor changes

We recommend that if retailers provide feedback through this consultation process to say they can't implement the 2b and 2c changes by 1 April 2026, then the 2a requirements on distributors should also be delayed to align with the retailers' capability to incorporate the rebate price signals and reward the respective injecting consumers. Failure to align the requirements under 2a and 2bc risks increasing costs to consumers in the short-term, with EDBs (and therefore consumers) paying twice – once for the rebate and once for the network investment that fails to be avoided by the injecting benefits not reaching the consumers who are injecting.

We also see little benefit in mandating a TOU change for only a subset of retailers. To maintain a level playing field, all retailers should be treated the same within pricing regulations. There are also regional differences in retailer market share. As currently drafted, the 2bc proposals could result in TOU pricing only being offered to consumers in certain locations, which seems contrary to the Authority's intent.

3.2.5 Updating the registry and standard application

It has been observed that there is sometimes inconsistent application of changes through the Registry. We recommend that either the final decision or associated guidance addresses the input requirements to ensure registry tags/labels are applied consistently across EDBs, ensuring easier billing for retailers.

3.2.6 Other practical implementation considerations

Impact on existing contracts

It would be good to understand the Authority's views on the impact of the proposed changes on existing and future contracts. Anecdotally, despite ACOT being revoked in December 2016, with final related payments expected in the 2017-18 pricing year, we understand that some ACOT payments are still being made due to the contractual arrangements in place and how difficult it can sometimes be to unwind contracts. There is risk that a similar situation could arise with the ECTF proposals.

Systems and processes

Implementing truly cost-reflective export pricing requires sophisticated systems and processes that don't currently exist at scale for most EDBs. EDBs need enhanced capability to identify constraints and identify a 'fair value' to pay for alleviating those constraints.

In the short term, this is likely to require EDBs to make simplifying assumptions and judgements, such as applying to all exports during winter peak periods, regardless of whether specific injections are demonstrably beneficial. This means that there are likely to be some wealth transfers required.

Ideally, EDBs would need mechanisms to signal these constraints dynamically, especially given the variability of constraints over different times and locations.

EDBs would also need systems to measure the response from consumers in order to calculate charges and rebates accurately, as well as to monitor the success of the interventions.

Framing of TOU requirements

The 2bc paper draft Code amendments refer repeatedly to "peak versus off-peak times during a day."[46] We are concerned this wording provides too much constraint within the definition of 'peak' and off-peak', for example, to include whole days being classed as 'off-peak' (i.e. weekends). We note that some distributors do not have peak periods in weekends, or at all outside of winter.

It would be good if this could be clarified either in the final decision, Code amendments or associated guidance materials.

3.3 Access to data

3.3.1 Access to data for more accurate signals

There is a gap between what is economically desirable and what is achievable with current tools. A perfect implementation would require better data access and probably billing system upgrades. To help ensure that networks are still meeting consumers' needs for reliability and stability, improved visibility of low-voltage networks will be critical to successful network transformation.

Network operators have good real-time visibility over their high and medium-voltage networks (typically 33,000 and 11,000 volts). But most lines companies want to improve real-time visibility of the status or performance of their LV networks, because the potential mass uptake of newer technologies - such as solar panels, batteries, and significant new loads such as electric vehicles - on to local networks increases both operational complexity and safety risks.

Lack of smart meter data and difficulties in attributing outcomes (behaviour change) to network pricing signals makes assessing the efficacy of cost-reflective or price-signalling distribution prices near impossible for EDBs. Without this feedback on the effectiveness or otherwise of distribution pricing in changing network use, EDBs are left dependent on more concrete actions, such as infrastructure upgrades or load control, to ensure they continue to meet consumer and regulator expectations on reliability and quality of service.

The Authority should therefore re-engage with the sector to improve the interchange of reliable and reasonably priced smart meter data.

[46] ECTF, Improving pricing plan options for consumers , 12 February 2025, page 62, amendment [00.1]

3.3.2 Requirements to charge using HHR data

Whilst we appreciate the Authority's assistance in helping EDBs access data through the [00.4] proposed Code amendment in the 2bc paper, most EDBs have created billing processes that allow for TOU pricing without half-hourly (HHR) data or data acquired through other sources. There are some concerns that the requirement under proposed Code amendment 12A.4 to mandate the use of half-hourly data provided by retailers will result in negative impacts.

The implication of these requirements is that EDBs will have to base their pricing on EIEP3[47] data files. Currently, EIEP1 files are more commonly used. Transitioning between these data types is likely to increase EDB costs, both to update systems and processes to use these data sets and also storage costs for the vast quantities of data, with no discernible benefit to consumers.

Concerns have also been raised by some EDBs who already receive half-hourly data from retailers that the data is often incomplete or inaccurate. As noted in the 2bc paper, "we understand some retailers' billing systems represent a barrier to the use of accurate data for billing and reconciliation, and some retailers will therefore face costs in meeting this part of the proposal. However, we consider the benefits of ensuring the use of accurate data outweigh these costs."[48]

Where does this leave EDBs if the retailers do not provide the half-hourly data in line with the time bands of the EDB's tariffs? Currently, most EDBs apply a default that if data is not provided with the right TOU bands, then the charges default to either the peak or shoulder rate.

Whilst we understand and support the intent of the proposal, we think there is a risk that mandating EDBs to use these data sets at the basis of their calculation of charges risks inaccurate charges, significant investment to reconcile/fix data prior to using it or non-compliance with the Code.

We recommend that should a Code amendment proceed, that the wording be amended to allow for more flexibility, such as "to the extent possible…" or "where practical to do so…"

3.4 Pricing principles

3.4.1 Comprehensive overhaul

ENA supports the Authority's option 4 in the DGPP paper advocating for comprehensive overhaul of the DGPPs. However, it is difficult to recommend option 4 without seeing further details about where the Authority intends to take this, so we provide support with caution.

Notably, we refer to the contrast we see in how the proposal is framed within the document. In one breath the Authority says that option 4's overhauls would result in less prescriptive new principles[49] and in another breath, the Authority suggests that similar principles to the connection pricing proposals from last year could be applied.[50] Our view is that these are quite contrary alternatives and could result in very different outcomes for EDBs.

Current rules and option 1 have a distortion effect

The current DGPPs, with their strict incremental cost limit, prevent distributors from efficiently planning for future distributed generation connections. This leads to poor investment signals,

[47] Electricity Information Exchange Protocols (EIEPs)
[48] ECTF, Improving pricing plan options for consumers , 12 February 2025, page 46, paragraph 6.86
[49] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 19, paragraph 3.26
[50] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 19, paragraph 3.29

discourages early investment due to first-mover disadvantage, and ultimately risks higher costs and reduced network reliability for consumers

Options 2 will not generate the best outcomes

As noted above, whilst it can be hard to give definitive views at an issues paper stage, without more substance around the proposals, in principle we agree that options 1-3 will not generate the best outcomes for EDBs or consumers or the system as a whole.

Option 2's proposal to make 'limited modifications' should not be supported because minor amendments to the DGPPs would not resolve the fundamental issues of inefficient pricing and planning. It retains a complex, highly prescriptive framework that limits distributors' flexibility and may continue to discourage efficient investment in both DG and the network.

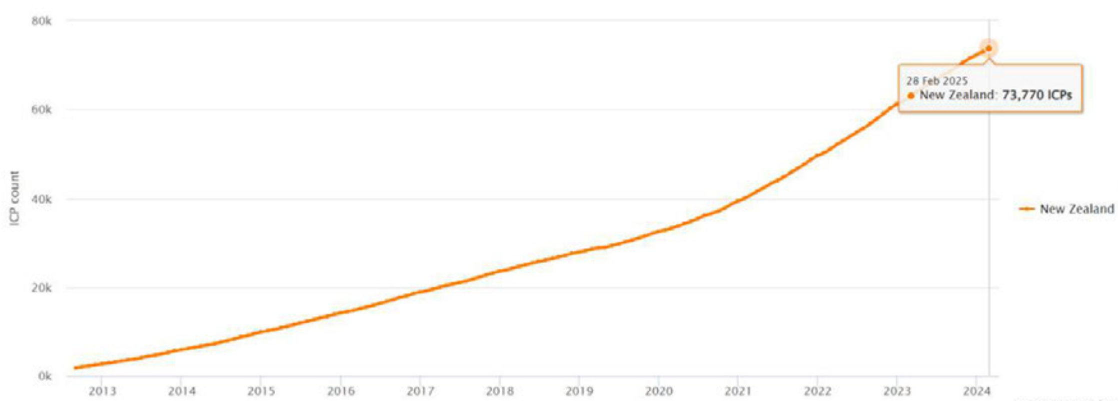
'Limited modifications' also risks creating a 'patchwork' of uncoordinated principles, which is more likely to result in confusion, poor regulatory drafting and inconsistent outcomes.

Option 3 may still have merit

Option 3 could have merit, and ENA does think that all outcomes should be left on the table when the comprehensive overhaul is undertaken, should option 4 proceed. A full review and more detailed analysis may still demonstrate value in option 3.

We are also not convinced that the Authority's arguments in the DGPP paper are reflective of EDB views or behaviour. Particularly, ENA questions whether the fact "Distributors are not required to contract with (or even to consider contracting with) DG as a non-network solution" justifies needing to regulate for this. Perhaps there is an under-utilisation of DG, aggregators and other non-network solutions at present.

Figure 1: Number of distributed generation installations[51]



Around the time the DGPPs were established, the ICP count of DG was around 20,000. In 2025, those numbers have more than tripled. A recent study by FlexTalk has also identified that many flexibility products underway have focused on identifying network management solutions, which includes DG-related initiatives.[52]

As this data implies, there are several examples of EDBs moving towards this approach even without regulatory intervention. The Commission has also established the Innovation and Non-Traditional

[51] Electricity Authority, Electricity Authority - EMI (market statistics and tools), 'Installed distributed generation trends' dashboard, filtered by fuel type 'all combined', accessed 21 March 2025
[52] EEA, FlexTalk flexibility scan published - eea.co.nz, accessed 21 March 2025

Solutions Allowance (INTSA), which might promote more of such activity than has occurred in the past. The Commission has added ID on non-network solutions and is looking for EDBs to demonstrate consideration of these when looking at business case optioneering. The Authority also notes the issues paper Commission's recent review found that current regulatory settings appropriately incentivised non-network solutions.[53]

It appears as if the Authority is trying to duplicate interventions before letting the current interventions become established and demonstrate their value. According to Government expectations, regulations should be "well-aligned with existing requirements in related or supporting regulatory systems through minimising unintended gaps or overlaps and inconsistent or duplicative requirements."[54]

So, whilst ENA supports option 4, it might be more reflective to say we support a comprehensive review of the current DGPPs, but consider that the Authority should keep an open mind with regards to the outcomes of that review.

3.4.2 Regulation in a competitive market

In relation to the 2bc paper, we note that the proposals are akin to imposing pricing principles on retailers. It is a common regulatory perspective worldwide that in competitive markets, prices (and associated offerings) are best set by market forces, with regulatory intervention reserved for preventing anti-competitive behaviours rather than imposing direct pricing rules.

We do not think the 2bc proposals are addressing anti-competitive behaviour. Instead, they are trying to use regulation of competitive entities to influence consumer behaviour in a way that may not align to how consumers want to behave. Please also refer to the section above on consumer behaviour.

3.4.3 Incremental cost

The principles currently say distributors can charge no more than the incremental cost of providing the connection for the service, which was intended to overcome bargaining-power differences between distributors and distributed generation investors, and to ensure a level playing field between network-connected and grid-connected generation.

The incremental cost principle was an important tool when DG needed support to enter the market. But these factors are less relevant today. Technological advances have reduced the costs of DG and lowered barriers to entry.

Now, it restricts efficient planning, creates pricing distortions, and inhibits the transition to a flexible, distributed energy system. In future, distributors could be augmenting their networks due to congestion being created by participants trading in various markets (e.g. virtual power plant providers), and there will need to be a way to recover those augmentation costs from the parties benefiting. Its removal would allow distributors to adopt more efficient, flexible pricing arrangements that better reflect the realities of today's electricity system.

Uneven playing field

Current DGPPs mean that DG could be incentivised to connect to local networks rather than to the grid.

---

[53] Electricity Authority, Distributed generation pricing principles, 12 February 2025, page 19, paragraph 3.25

[54] Treasury, Government Expectations for Good Regulatory Practice, April 2017, page 4

The incremental cost principle prevents EDBs from allocating shared costs, including transmission connection charges[55] to DG. The transmission pricing methodology (TPM) has no such limitations. This creates an uneven playing field, where shared costs that would normally be evenly allocated based on connection characteristics in accordance with the pricing methodology are only funded by a subset of connections.

When a grid-scale generator connects via an EDB, the DG pricing principles mean that the EDB can only allocate the incremental cost to the generator. Typically, this is limited to the increase in interconnection charges. This means grid-scale generators can avoid paying a share of connection charges by connecting as a DG, rather than connecting directly to the grid. Even if the physical and engineering requirements of the generator are the same.

DG participants are shielded from shared costs, potentially incentivising DG investments in locations or at scales that do not align with overall system efficiency.

This has a direct impact on consumers. If DG connects to the local network, as they cannot be charged for a share of the common costs, consumers pay for 100% of these, including the transmission connection charges. We note that Horizon's submission on the DGPP issues paper includes some specific examples of this, including the significant financial impacts.

Cost-reflective pricing

A key principle of an efficient electricity market is cost-reflective pricing—where prices accurately signal the costs and benefits of participants' actions on the system. Cost-reflective pricing encourages efficient investment and operation decisions by all participants, including distributed generators, consumers, and network owners. It ensures that those who create costs (or deliver benefits) to the network are appropriately charged (or rewarded), promoting fairness and efficiency in the allocation of network resources.

The strict incremental cost approach in the current DGPPs limits the ability of distributors to set cost-reflective prices by not allowing them to recover the full costs that DG can impose on the network. These costs can include investments in network capacity, voltage management, monitoring, and protection schemes that are necessary to safely and reliably accommodate DG. When DG participants do not face price signals reflecting these broader costs, there is a risk of inefficient investment decisions, leading to network congestion, voltage issues, and ultimately higher costs for other network users.

To enable cost-reflective pricing and encourage efficient outcomes, we support the removal of the incremental cost principle from the DGPP framework. This will provide distributors with the flexibility to recover appropriate costs, support investment in non-network solutions, and deliver better outcomes for consumers and the energy system as a whole.

3.4.4 'Principles' vs 'rules' and flexibility outside of the Code

The electricity sector is undergoing a rapid transition, driven by the uptake of distributed energy resources (DER), evolving consumer preferences, and advances in flexibility services. As we move into this new era, it is crucial that the regulatory framework supports innovation, learning, and adaptation. In this context, we strongly advocate for a principles-based approach, rather than prescriptive rules embedded within the Code.

Prescriptive rules are often rigid and difficult to amend in response to new technologies and changing market conditions. History demonstrates that embedding highly detailed rules, and even principles, within the Code can lead to regulatory lag, where outdated provisions hinder progress and limit

[55] Except where there is an increase in connection charges that is directly attributable to the DG.

participants' ability to innovate. The current DGPP framework, particularly the incremental cost principle, offers a case in point—rules and principles that were once appropriate have now become a barrier to efficient network pricing and distributed generation integration. We are concerned that codifying new flexibility arrangements too early could result in a similar situation, where participants are bound by rules that no longer reflect the realities of the market.

In contrast, principles-based regulation outside of the Code offers the necessary flexibility to adapt as the sector learns and evolves. Principles can guide participant behaviour towards desired outcomes—such as efficiency, fairness, and transparency—while leaving room for different approaches to meet these objectives. This allows distributors, aggregators, and other participants to develop tailored solutions that reflect the specific characteristics of their networks and customers. It also enables the Electricity Authority to monitor market developments and provide guidance, without the rigidity of formal rule changes.

During this transitional phase, the sector is still exploring the most effective ways to integrate flexibility services, distributed generation, and consumer participation. We believe that principles held outside the Code, supported by information disclosure, monitoring, and industry collaboration, will foster innovation and allow for iterative improvement. This approach reduces the risk of unintended consequences that could arise from overly prescriptive regulation and ensures that the regulatory framework remains fit-for-purpose as technologies and business models mature.

In summary, we encourage the Authority to adopt a principles-based approach to flexibility, avoiding hard-coded rules until there is sufficient learning and experience to justify a more structured framework. This will help ensure that regulation enables, rather than constrains, the development of efficient and competitive flexibility markets that deliver benefits to consumers.

3.4.5 Consistency

Consistency within distribution pricing

It appears ironic that the Authority's studies into DG connections demonstrate that distributors are under-recovering their costs for DG connections,[56] whilst only a few months ago, they released a paper on load connections suggesting (without presenting any evidence) that distributors were over-recovering load connection costs and needed regulation to control costs.[57]

The DGPP paper says "the DGPPs make it harder to host DG by limiting how distributors can recover costs related to DG."[58] Arguably, the Distribution connection pricing proposed Code amendment consultation paper seeks to further such challenges by extending limitations to load and well as DG.[59]

It appears that there are silos at the Authority and that different teams are not aligning their approaches, leading to inconsistent approaches being proposed by the Authority. We think there is value in all pricing-related matters being considered in a consistent way. A starting point for this could be to relate all new papers back to the 2019 pricing principles.

A single set of consolidated pricing principles could avoid a lot of confusion and rework within the sector. It is also inefficient to be reconsidering principles every few years in small increments. A coordinated approach is also less likely to result in drafting examples such as in the 2bc paper, where 'lazy drafting' is suggesting a clause be added to override all other associated clauses.

[56] Electricity Authority, Distributed generation pricing principles, page 9, paragraph 2.9
[57] Electricity Authority, Distribution connection pricing proposed Code amendment
[58] Electricity Authority, Distributed generation pricing principles, page 9, paragraph 2.8
[59] Electricity Authority, Distribution connection pricing proposed Code amendment

Consistency between transmission and distribution pricing

As discussed under the 'incremental cost' section above, inconsistency exists between transmission and distribution pricing principles, which distorts pricing incentives for connecting DG.

It would be beneficial if the Authority were to consider consistency between different parts of the wider system prior to making future changes.

Long-term stability

ENA members believe that local generation is entitled to consistency and longer-term stability in regulatory decision-making, in the same manner as for any other market participant.

The transaction costs and practicality of changing the DGPP in the manner proposed by the Authority should not be underestimated. There will be a need to renegotiate numerous existing contracts and for EDBs and DG, potentially also with impacts to other market participants, to review their approaches to pricing and connection policies.

The more coordinated the review of principles is, the more likely it is that we achieve more stable outcomes. Principles outside of the Code will also likely reduce the impact of future amendments.

3.5 Focused regulatory interventions

3.5.1 Focus on the 'biggest bang for buck'

The proposals in the current set of consultations just tweak at the edges, while apparently hoping for transformative change.

ENA notes that the ECTF was explicitly established to address wholesale market volatility and unprecedented spikes in wholesale prices. As stated in its Terms of Reference, the Task Force was formed in direct response to "fuel scarcity combined with lag in new investment in generation [which] has created conditions leading to unprecedented spikes in wholesale prices."[60] The Task Force was intended to "urgently consider the complex factors underlying wholesale prices."[61]

It seems as if the Task Force is 'messing about at the edges' and making minor tweaks that won't get to the heart of the affordability or security of supply challenges.

We note that in the 2a paper, for example, the ECTF refers to the "significant benefits" of DG supplying surplus energy at peak times. And yet, the estimated rebates calculated in Appendix A suggest that the likely impact per consumer is less than $12 per annum, if that. Vector, with a market share of around 25%, is expected not to pay anything under the ECTF's principles.[62]

The transient and unpredictable nature of home generation and its associated exports are also unlikely to materially reduce network investment. The 2a proposals are neither going to make a material impact on user bills, nor materially change the economics for those considering whether or not to invest in solar and batteries.

The investment in time by the ECTF, Authority, and all those engaged in this consultation process is likely to exceed the financial benefit of the proposal. Just in reviewing and responding to these

[60] ECTF, Terms of Reference for the Energy Competition Task Force, August 2024
[61] ECTF, Terms of Reference for the Energy Competition Task Force, August 2024
[62] ECTF, Requiring distributors to pay a rebate when consumers supply electricity at peak times, 12 February 2025, page 40, table 5

consultations alone, the sector is likely to have spent more on staff time (and therefore salaries) than the expected consumer bill benefit.

The ECTF and the Authority should be focusing on the interventions that will generate the best/biggest impacts and most significantly move the dial for greater energy security and affordability. Examples could include:

- Greater focus on fundamental issues in the wholesale market
- Increasing supply, such as increasing generation options and investment (e.g. working with MBIE to expedite a decision on allowing EDBs to increase their generation capacity)
- Working with MBIE or others to make incentives available for installing equipment that can provide flexibility services. This could include capital grants, subsidies, or rebate schemes specifically for battery storage systems, smart inverters, home energy management systems, and other technologies that enable active participation in flexibility market
- Coordinating to improve the Building Code to enable more smart EV chargers or smart commercial/residential buildings with energy management systems.

3.5.2 Regulatory burden

Too Many Changes, Too Quickly

We acknowledge the Authority's role in driving important market reforms. However, we are increasingly concerned that the current pace and volume of proposed regulatory changes are placing an unsustainable burden on industry participants. Resource-constrained businesses, including EDBs, retailers and other service providers, are grappling with multiple overlapping consultations and implementation projects. The sheer volume of change risks undermining effective engagement, reducing the quality of industry feedback, and ultimately compromising the success of reforms.

Whilst each intervention may not appear material or burdensome in isolation, when packaged with all the other overlapping changes, many organisations are struggling to cope. There is a risk this results in poor implementation, diversion of resources from other projects, higher costs and negative impacts on consumers.

Urgency versus quality

It is critical to balance urgency with quality. Rushed or piecemeal regulation often results in unintended consequences, confusion and costly remediation. We believe the Authority and the ECTF are prioritising speed over sound process, evident in proposals that deliver minimal benefit (such as the proposed 2a rebate, delivering a consumer benefit of circa $12 per annum per ICP, but being hailed as a proposal that will influence consumer decision-making when it comes to investing $22,000 to $37,000 on a solar and battery system. Such interventions are unlikely to change consumer behaviour or materially improve market efficiency.

Regulatory interventions must be proportionate to the scale of the problem they seek to address. Minor gains that come at a significant compliance cost fail the basic test of cost-benefit justification.

Inconsistent Code amendments and regulatory integrity

The proposals to which this paper is responding imply that the Authority and the ECTF are prioritising doing things 'quickly' rather than doing things 'right'. Recent 'lazy drafting' amendments have led to inconsistencies, conflicting provisions and increased complexity.

Examples include proposed amendments like the 2bc proposals, which state: "despite anything else in this Code or in a distributor agreement, distributors must…"[63] This form of blanket override, without properly integrating the changes into existing Code provisions, creates legal uncertainty and compliance risks for participants.

This drafting approach is contrary to New Zealand Government expectations for good regulatory practice, specifically the requirement that regulations be "well-aligned with existing requirements in related or supporting regulatory systems through minimising unintended gaps or overlaps and inconsistent or duplicative requirements."[64]

Poor regulatory drafting not only increases the risk of non-compliance but also diverts valuable time and resources away from activities that directly benefit consumers.

The Authority's reliance on overrides and exceptions, rather than undertaking a comprehensive and structured update of the Code, signals expediency over quality.

As an industry, we need coherent, navigable, and durable regulations—rules that are "easy to find, easy to navigate, and clear and easy to understand."[65]

We recommend a comprehensive tidy-up and rationalisation of the Code. The current patchwork of amendments risks undermining confidence in the regulatory framework and creates barriers to efficient participation and investment. We encourage the Authority to prioritise code cohesion and consistency over fragmented, isolated changes.

Overly prescriptive or hastily implemented rules risk creating long-term inefficiencies and regulatory debt—where constant patching and amendment are required to maintain relevance.

3.5.3 Recommendations for smarter, adaptive regulation

We believe the Authority can enhance the effectiveness of its regulatory framework by:

- **Embedding trials, sunset clauses, and mandatory review periods** in all new regulations, to ensure they remain fit-for-purpose and can be adjusted or removed if circumstances change.
- **Avoiding overrides and 'patchwork' drafting** and instead prioritising cohesive and comprehensive Code amendments that align with principles of good legislative design.
- **Focusing on quality over speed**, ensuring regulatory proposals are robust, have clear problem statements, and undergo thorough impact assessments before implementation.
- **Maintaining flexibility** by developing **principles-based approaches**, particularly in areas of rapid innovation such as flexibility services and DER integration, where the full scope of potential risks and benefits is not yet fully understood.

[63] Energy Competition Task Force, Improving pricing plan options for consumers,12 February 2025, page 64
[64] Treasury, Government Expectations for Good Regulatory Practice, April 2017, page 4
[65] Treasury, Government Expectations for Good Regulatory Practice, April 2017, page 4

Appendix A: ENA Members

Electricity Networks Aotearoa makes this submission along with the support of its members, listed below:

- Alpine Energy
- Aurora Energy
- Buller Electricity
- Centralines
- Counties Energy
- Electra
- EA Networks
- Firstlight Network
- Horizon Networks
- Mainpower
- Marlborough Lines
- Nelson Electricity
- Network Tasman
- Network Waitaki
- Northpower
- Orion New Zealand
- Powerco
- PowerNet (which manages The Power Company, Electricity Invercargill, OtagoNet and Lakeland Network)
- Scanpower
- Top Energy
- The Lines Company
- Unison Networks
- Vector
- Waipa Networks
- WEL Networks
- Wellington Electricity
- Westpower

Appendix B: Initiative 2a – Requiring distributors to pay a rebate when consumers supply electricity at peak times

ENA responses to the ECTF's specific consultation questions

Questions	ENA Comments
Problem definition	
Q1. Do you agree with the problem definition above? Why, why not?	Not fully. The existing distribution pricing principles contain a requirement to consider avoided costs. The 2a proposals are therefore not materially different from existing requirements – perhaps just a little more explicit. It is therefore already a consideration for EDBs to identify, assess and offset any cost savings within pricing. If this is not being done, it is likely because such savings and network benefits are not deemed to exist, or to not be material enough to implement on the basis of a cost-benefit assessment. Whilst ENA understands and supports the Task Force's intent, we believe the problem statement overestimates the network benefits generated by small-scale ad hoc consumer injections, as well as overestimating the impact that these small rebates will have on influencing consumer behaviour and investment decisions. The problem definition also fails to adequately address the complexities of network constraints and the challenges in implementing location-specific rebates that deliver genuine network benefits. The problem statement also seems to underestimate the potential risk the rebate proposals will have on developing a more sophisticated flexibility services market. We are also not convinced that the 2a proposals are really within the remit of the Task Force and its priorities in relation to affordability and security of supply. Please refer to section 3.1 of this submission for more on all of the above points.
Proposed solution: principles-based rebates	
Q2. Do you agree with these principles? Why, why not?	ENA does not believe there is significant value in offering rebates to consumers exporting at peak times. Using the ECTF's own calculations, this is likely to result in rebates of less than $12 per year per customer. For the time and effort involved, there is not really a material benefit to consumers. However, of the alternatives proposed, we agree with the Authority that a principles basis is the most appropriate approach to implement this. One of the most important elements of the principles to retain in a final decision is "at times when the injection provides

Questions	ENA Comments
	network benefits" consistent with demand pricing and distribution pricing principles. As discussed further in section 3.1.2, not all injection of surplus power will generate network benefits and failure to include this principle could result in higher overall costs for consumers. Rebates should only be payable if the injection results in genuine and demonstrable network benefits.
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?	Yes. ENA agrees that these principles should only apply to mass-market consumers. Whilst EDBs may choose to apply the principles voluntarily to larger consumers and generators, there needs to be more flexibility to manage the differences with these consumers. Larger consumers and generators are likely to have more sophisticated arrangements in place.
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)?	Potentially. We think it is reasonable for the principles to apply to all mass-market DG as long as the principle in relation to proving network benefits remains. However, as noted in the paper, it is unlikely that inflexible generation will meet the criteria to generate a rebate payment. Our main concerns with broad application are: - that consumers may become misled into believing they will receive a 'guaranteed' rebate. It will be important to monitor how the rebates are described and advertised to consumers, including by the Authority and ECTF in their announcements. - that through simplifying assumptions required by EDBs in lieu of quality data and sophisticated systems on which to base calculations, inflexible generation may become rewarded for benefits they don't offer.
Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?	ENA supports the use of guidance to help ensure EDBs implement solutions that are broadly consistent. Any guidance should be developed in collaboration with stakeholders and released in a timely manner. EDBs will rely on guidance to inform the system and process changes required to implement the amendments. As such, implementation timeframes should factor in the release of guidance. No EDB efforts to implement principles should be expected to be made until the guidance is finalised. Some members have also highlighted that there may be inconsistencies in the guidance as currently proposed in the 2a paper. Some of these inconsistencies have been described further in section 3 above. However, we also encourage the ECTF to consider individual EDB submissions for more examples.
Q6. Are there any additional issues with the principles where guidance would be particularly helpful?	On the proviso that guidance is developed in conjunction with EDBs, ENA suggests that guidance on the following may be helpful: - How to define and measure "network benefits".

Questions	ENA Comments
	- The appropriate level of rebates for a network benefit and consistency with demand pricing. - How to integrate rebates with other flexibility mechanisms. - The treatment of rebates in regions with multiple constraints affecting different network levels. - How to handle the potential for constraints to shift over time due to network reconfiguration. - How to address consumer equity concerns when rebates are available in some areas but not others. It would also be useful to understand how the rebates can and should be monitored. There needs to be mechanisms to assess whether consumers are receiving the price signals, or whether the rebates are being taken as 'windfall gains' by retailers. A feedback loop for the effectiveness of the rebates and guidance on how to demonstrate that network benefits are being realised may help.
Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?	No. ENA believes the best approach would be voluntary principles that could be applied and monitored outside of the Code. Given the cost-benefit analysis (CBA) on this is likely marginal at best, voluntary principles could better support the wide range of EDBs. For some regions, they are years away from expecting congestion on their networks and/or have very limited DG exposure. Mandatory principles would likely result in costs far exceeding the benefits on some networks – costs that will ultimately be borne by local consumers. Refer to section 3.4.4 for more discussion around this point.
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.	We refer the ECTF to section 3.2.3 above for a more detailed discussion around implementation timeframes. In summary, EDBs are at different maturity levels and it may not be realistic in most cases for implementation in line with the proposed schedule. We also note there is some ambiguity in what the ECTF is actually proposing and there may be a misunderstanding by the ECTF on which pricing year the changes will start in. We also reiterate that the decisions on the 2bc paper should also be considered for the 2a proposals. If retailers are not able to comply with the 2bc proposals, there is risk of higher short-term consumer costs by implementing the 2a proposals earlier than 2bc.
Q9. Do you agree the proposal strikes the right balance between encouraging price-based flexibility and contracted flexibility? Why, why not?	The rebates are likely to be so immaterial, at least in the short term, that it doesn't seem that this proposal will make any material impact on flexibility.

Questions	ENA Comments
	Please also refer to section 3.1.11 for more discussion around flexibility services and aggregators.
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?	Whilst the principles limiting application where there are network benefits should minimise risks of wealth transfer, we think there is still a risk that the costs will outweigh the benefits of this proposal. The rebate levels are too small to drive significant mass-market consumer investment, and the anticipated network benefits may not materialise at the scale required to offset costs, leading to higher costs for all consumers. Please refer to section 3.1 for more discussion in relation to these risks.
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?	Yes. Prescriptive rates are unlikely to consider the differences between networks and the impacts of injection. There is a greater chance that prescriptive rates will result in higher costs for consumers. If the rates are not principled, rebates will be paid for injection that does not result in network benefits, therefore increasing costs for consumers as a whole. We support the Authority's principles-based approach. Please refer to section 3.1.4 for more discussion on the prescribed rates alternative option.
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?	We agree with the Authority's analysis, and that consumption-linked injection tariffs should not be preferred. Please refer to section 3.1.5 for more discussion on asymmetrical rates.
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?	Refer to response to Q12 above.
Regulatory statement	
Q14. Do you agree with the objective of the proposed amendment? If not, why not?	While we agree with the objective to "incentivise investment in and operation of DG when and where it provides network benefits by avoiding or deferring network costs,"[66] we are not convinced the proposed amendment will achieve this objective in a meaningful way.

[66] Energy Competition Task Force, Requiring distributors to pay a rebate when consumers supply electricity at peak times, page 30, paras 6.2 and 6.3

Questions	ENA Comments
	However, we accept that this proposal is, perhaps, a 'no regrets' starting point for such incentives.
Q15. Do you agree the benefits of the proposed amendment outweigh the costs?	This is hard to assess with certainty at this stage. Based on the experience of some of our members with trials and other similar arrangements, providing an 'accurate' response to the proposal is likely to incur significant implementation costs. A more 'high-level' and less targeted approach, such as applying rebates to all exports at winter peak, regardless of whether a network benefit can be demonstrated in all cases, may be more achievable. Either way, this appears to be a marginal proposal, which is unlikely to deliver material benefits. We discuss this further in section 3.1 and 3.5.1 above.
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.	Yes. Of the options presented, a principles-based approach is preferable to prescribed rebates or consumption-linked tariffs. However, we believe that allowing flexibility services markets to develop naturally, supported by appropriate regulatory frameworks, would be a more effective approach to delivering network benefits from distributed generation.
Q17. Do you have any comments on the drafting of the proposed amendment?	The policy intent of the consultation paper is to ensure that distributors pay a rebate when consumers supply electricity at peak times. Distributors are wholesale providers of line services to retailers. While distributors may have direct contracts with very large end-customers, for mass-market customers EDBs contract with retailers, who in turn contract with end-customers. We question whether the Code amendment, as currently proposed, confuses this issue by referring to 'customers'. Please also refer to 3.1.8 and our responses to Q4 and Q5 in Appendix C for more on this issue. We also refer you to section 3.5 for more discussion around regulation and section 3.4.4 in relation to the preference for principles outside of the Code.

Appendix C: Initiative 2b & 2c – Improving pricing plan options for consumers – time-varying retail pricing for electricity consumption and supply

ENA responses to the ECTF's specific consultation questions

Questions	ENA Comments
Q1. Do you agree the issues identified by the Authority are worthy of attention? If not, why not?	ENA agrees that improving pricing options for consumers is worthy of attention. However, we are concerned that the proposed approaches may not deliver the intended benefits and could create unintended consequences, particularly the requirement for distributors to use half-hourly data for billing purposes. Please refer to section 3.3.2 above for more discussion around the half-hourly data requirement. Please refer to section 3.1 (and particularly 3.1.7 and 3.1.10) for more about these proposals more generally.
Q2. Which option do you consider best addresses the issues and promotes the Authority's main objective? Are there other options we have not considered?	Previous examples of EDB consultation with customers in relation to TOU plans have indicated approximately a 50/50 split in terms of support. There is a material risk that mandatory TOU plans would penalise consumers who, due to their circumstances, can't shift their load. This is a poor consumer outcome. ENA supports giving consumers the choice to opt for a TOU plan, but not mandating or defaulting to TOU plans. ENA also believes that allowing distributors flexibility in how they implement time-varying pricing, rather than mandating specific approaches like half-hourly data use, would better promote the Authority's objectives. Please refer to section 3.3.2 above for more discussion around the half-hourly data requirement. Please refer to section 3.1 (and particularly 3.1.7 and 3.1.10) for more about these proposals more generally. Section 3.1.7 also includes a discussion of alternatives to TOU that the Task Force may not have considered.

Questions	ENA Comments
Q3. Should we require retailers to offer a price plan with time-varying prices for both consumption and injection? Why or why not?	Over 70% of EDBs offer pricing on a time-varying basis. It seems reasonable that, where available, these options are passed onto consumers in some form. Time-varying plans can incentivise consumers to shift their consumption away from peak (or shift their injections into peak) to help manage congestion. However, we do note that only some demand is elastic enough to make use of time-varying arrangements. The object of time-varying pricing is to inform consumption and injection decisions, but not necessarily to change them. Leaving the choice to consumers seems the appropriate way to maximise benefits though. Consumers that have elastic demand that they can shift can take up time-varying price plans and those who can't or don't want to adjust their consumption/ export can remain on non-time-varying plans. Eventually the level of non-time-varying prices will adjust to ensure they, too, are cost-reflective (a flat tariff can also be cost-reflective). Please refer to section 3.1.10 for more discussion around consumers. Price signals and robustness of time-varying plans can be improved through more accurate and detailed data, which in many cases EDBs and retailers don't have access to. We refer you to section 3.3 of this submission for more on access to data.
Q4. Do you have any feedback on the design requirements?	Please refer to 3.2.5 and 3.2.6 in relation to practical implementation matters in relation to the TOU proposals. It is important that retailers are not unnecessarily restricted from offering packages that encourage load shifting and injection and may resonate with customers, including free hours (or days) of power, appliances, zero bills for a period, or other rewards and inducements. The current drafting risks pigeon-holing benefits to a line item on a customer's bill. That said, should the retailers' offers not incentivise consumers in a way that generates network benefits, network pricing (including export rebates) should be sufficiently flexible to adjust for this to avoid unnecessary additional costs for consumers (e.g. paying for the rebates and the investment that was not able to be avoided or deferred due to benefits not being realised). Please also refer to 3.1.8 for a discussion around price signals and the diversity of EDB views on this subject.

Questions	ENA Comments
Q5. Is there a risk that injection rebates will not be passed through to the consumers targeted? If so, how could we safeguard against this risk?	Yes. We know that several EDBs have discussed rebates with retailers in recent times and that some retailers have indicated a lack of willingness to pass these through. Please also refer to 3.1.8 for a discussion around price signals and the diversity of EDB views on this subject.
Q6. Which retailers should be captured by the proposal and why?	All retailers should be captured. Applying regulations unevenly risks distorting competition amongst retailers and distorting consumer benefits. Please also refer to 3.4.2 for a discussion around regulation in competitive markets and our response to Q4 above.
Q7. What are your views on the proposed timeframe for implementation of 1 January 2026? Would 1 April 2026 be preferable, and if so why?	Aligning price changes to the network pricing year is likely to provide more stability and predictability for consumers. We therefore recommend a 1 April implementation. ENA doesn't express an opinion on whether retailer will be able to make the required process and system changes in time for 1 April 2026. However, we are aware that retailers are under the same regulatory pressure as EDBs at present and are likely to have challenges. Refer to section 3.5.2 for more on sector pressures, as well as 3.2.3 for a specific discussion around timeframes. However, given there is a so-called 'pass-through' element relating to the 2a requirements on distributors to pay rebates to customers for exporting electricity at peak, there should be alignment on that part of the implementation. I.e. if feedback is that retailers cannot implement the changes until 1 April 2027, then the requirement on distributors should also be deferred to 1 April 2027. Refer also to our response to Q8 in Appendix B.
Q8. What are your views on Part 2 of our proposal that would require retailers to promote the time-varying price plans?	Please refer to section 3.4.2 and 3.1.10.
Q9. What should the Authority consider when establishing the approach to and format of the reporting regime?	Ideally, any reporting or monitoring of proposals such as these should allow for an assessment of the effectiveness of implementation against the objectives.
Q10. Should the Authority include a sunset provision in the Code, or a review provision? Why?	ENA considers that a review provision is advisable on any new regulation introduced. Without a requirement to review, there is a risk that regulations become entrenched without delivering the benefits they were intended to create.

Questions	ENA Comments
	Refer also to 3.5.3.
Q11. What are your overall views on Part 3 of the proposal?	No further comments.
Q12. What are your views on Part 4 of our proposal to amend the Code to require that consumers are assigned to time-varying distribution charges, that retailers provide half-hourly data to distributors for settlement?	While ENA supports retailers providing half-hourly data to distributors, we oppose mandating the use of half-hourly data for billing purposes. Many EDBs currently use EIEP1 files with defined time-of-use bands to achieve the same outcome without the significant costs and complexity of utilising EIEP3 files. Refer to section 3.3.2 for more information.
Q13. Do you agree with the objective of the proposed amendment? If not, why not?	We agree with the Task Force's objective of improving pricing options for consumers. We question whether such intervention is really needed. Refer to section 3.4.2 and 3.1.10. We disagree with the proposed implementation approach regarding mandating half-hourly data for distributor billing. The objective could be achieved through less prescriptive approaches that allow distributors flexibility in how they implement time-varying pricing.
Q14. Do you agree the benefits of the proposed amendment outweigh its costs?	For Part 4 regarding half-hourly data for billing, the benefits do not outweigh the costs. Most EDBs already offer TOU billing, so these changes would override long-established processes and systems. The proposal lacks a quantitative cost-benefit analysis that accounts for data storage and processing requirements.
Q15. 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.	With regards to Part 4, there are simpler, less costly approaches to achieving the same objectives, such as our current approach using EIEP1 files with defined time-of-use bands. The proposed amendment is unnecessarily prescriptive and does not allow for innovation and efficiency in how distributors implement time-varying pricing.
Q16. Do you have any comments on the drafting of the proposed amendment?	ENA strongly objects to the proposed drafting in relation to 12A.4 that uses "despite anything else in this Code or in a distributor agreement, distributors must..."[67] This is an example of very bad regulatory practice, which will increase confusion and complexity. Please refer to section 3.5.2 and 3.5.3 for more on this.

[67] Energy Competition Task Force, Improving pricing plan options for consumers,12 February 2025, page 64

Appendix D: Distributed generation pricing principles issues paper

ENA responses to the Authority's specific consultation questions

Questions	ENA Comments
Q1. Do you have a view on the definition of incremental cost that is contained in the Code? Should it be more tightly defined to include only network costs and to exclude consequential costs relating to factors such as frequency keeping and voltage support? Would this lead to more timely generation build and lower energy costs?	ENA recommends that the Authority look holistically at its pricing principles and ensure consistent definitions for common terms are applied.
Q2. Do you agree with the problems with the incremental cost limit identified in this section? Why or why not? Do you have a view on the relative importance of the problems identified?	Yes. We agree that the incremental cost principle restricts efficient planning, creates pricing distortions, and inhibits the transition to a flexible, distributed energy system. Refer to section 3.4 above for a more fulsome discussion around incremental cost.
Q3. Do you agree circumstances have changed significantly since the DGPPs were introduced, including that there are now far fewer impediments to distributed generation than in the early 2000s?	As discussed further in section 3.4, there has been a significant uptake in DG since the DGPPs were established and it does appear that there are fewer impediments.
Q4. Do you agree with the assessment of the current situation and implications of incremental cost pricing? If not, why not? What if any other significant factors should the Authority be considering?	We agree that the current situation is resulting in unintended consequences that increase costs to consumers and incentivise inefficient behaviour. Refer to section 3.4 above for a more fulsome discussion around incremental cost.
Q5. Do you agree these are the appropriate options to consider?	Yes, these appear to be reasonable options to consider. Refer to section 3.4.1 for a discussion of the options.
Q6. Are there other options the Authority should consider for improving rules about costs that can be recovered from distributed generators?	ENA advocates for consistency in relation to pricing and pricing principles. As discussed further in section 3.4.5 and in relation to Q1 above, we think the Authority should apply consistency in its approach to various pricing principles.
Q7. Will new aggregator business models emerge to solve the problem?	Aggregator business models are unlikely to solve the problem that the DGPPs prevent shared costs from being borne by DGs, and as a result incentivise inefficient behaviour and inefficient

Questions	ENA Comments
	pricing. Refer to section 3.4.3 for further discussion of incremental cost and its associated issues. Aggregators do have value to provide though, which is discussed further in section 3.1.11.
Q8. Are distribution price signals alternative to, or complementary to contracting?	Within the context of the consultation paper, distribution price signals are a way of signalling where DG is providing a benefit to the network. Similar to how contracting for demand response is an alternative to TOU pricing, both incentivise behaviour but contracting provides a guaranteed level of service.
Q9. Which, if any of the above options, do you consider would best support efficient pricing for recovery of distribution costs from DG?	ENA supports a comprehensive review of the DGPPs, but encourages the Authority to keep an open mind as to the outcome of the review. We think there may be merit in both options 3 and 4. This is further discussed in section 3.4.1 above.
Q10. Do you agree with the Authority's tentative view on a solution? In particular: • Should efficient price signals be sent through a revised set of pricing principles? • Would voluntary guidelines or mandating through the Code be the best approach? • Should we rely on the distribution pricing principles outside the Code or codified new pricing principles for DG? Why?	ENA agrees that revised principles would be helpful. ENA thinks that voluntary guidelines outside of the Code would be an efficient and effective approach from the Authority. Consistent with the distribution pricing principles, these should be voluntary, but supported by guidance and a 'scorecard' monitoring regime. Should the Authority then feel that the principles are not being followed or driving the right behaviours, the Authority could reconsider the approach at a suitable future date. If DG is generating benefits to consumers and networks, there should be a natural incentive for networks to apply the principles without the need for regulatory 'sticks'. Refer to sections 3.4.4, 3.4.5 and 3.5 above.
Q11. Are there any unintended consequences from removing the existing DGPPs? • Do you agree with the risks we have identified, and our assessment of them? • Do you think there are any other risks we should consider associated with the removal of the DGPPs? • Do you have any information that would allow the Authority to better assess such risks?	There may be impacts on existing contracts that should be considered (refer section 3.2.6). Otherwise, we also refer to section 3.4.4, 3.4.5 and 3.5 for other factors the Authority should consider.

Questions	ENA Comments
Q12. Do you agree market and regulatory settings provide efficient incentives for DG reducing or avoiding transmission costs? What, if any, other significant factors or options should the Authority consider?	From a network perspective DG does not appear to reduce or avoid transmission charges. Transmission charges are fixed and do not reduce when DG is connected.