Targeted Reform of Distribution Pricing

Issues paper

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ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

Distribution networks have a critical role to play in the electrification of New Zealand's economy.[1] The Government has a target of net zero greenhouse gas emissions by 2050 and an aspirational target of 100 percent renewable electricity generation by 2030.[2] Electrification of transport and process heat will lead to a substantial increase in electricity demand during the transition to this low-emissions future. Much of this new load will be connected to distribution networks and some of it will be supplied by distributed energy resources.

Meeting the demands of the energy transition will require billions of dollars of investment in network infrastructure.[3] This is in addition to the investment required to increase resilience to adverse weather events, which has become apparent in the wake of Cyclone Gabrielle. The Electricity Authority (Authority) is conscious of the potential impact on consumers of these increased costs.

This paper discusses the regulatory settings for distribution pricing and how to ensure they support the shift to a low emissions future at the least cost to consumers.

Transitioning to a low-emissions economy at the least cost to consumers

Efficient distribution pricing can support an affordable transition to a low-emissions economy – by providing appropriate signals to consumers as they consider their own power use and respond. With projections of over $20 billion of distribution-related investment in each of the next three decades, cost-reflective prices, which send efficient signals of the cost consequences of network usage, will be crucial for helping direct users toward lowest-cost usage and investment choices. Such cost-reflective prices, by coordinating network usage and encouraging the right investment to occur in the right place at the right time, could save consumers billions of dollars through economising on investment in the coming years.

The Authority is committed to ensuring that reform of distribution pricing occurs in a timely manner. The Authority has been working steadily on distribution pricing reform over the past few years with an increasing focus on its important role in enabling an affordable transition to a low-emissions economy:[4]

> *By encouraging more efficient use of and investment in electricity networks, efficient distribution pricing leads to relatively lower prices for electricity consumers in the long-term. Promoting efficient electricity infrastructure investment will be particularly important as New Zealand electrifies its transport fleet and industrial processes over the next 30 years to support its transition to a low-emissions economy.*

The Authority has supported reform in recent years through publication of distribution pricing principles, a distribution pricing practice note and a scorecards assessment to monitor and comment on distributors' pricing methodologies. The current approach has had some success, with some notable improvements in pricing methodologies by some distributors.

However, based on the evidence gathered from scorecards assessments since 2019,[5] and analysis of other disclosed information, the Authority is concerned that progress toward more cost-reflective pricing is not occurring as consistently or as rapidly as required.

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[1] Distribution networks take electricity from the transmission grid to the connection point for a property.
[2] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/
Note: the target is for net zero greenhouse gas emissions by 2050 (*other than for biogenic methane*).
[3] *The Future is Electric: a Decarbonisation Roadmap for New Zealand's Electricity Sector*, October 2022, Boston Consulting Group, page 118
[4] *Distribution Pricing Practice Note,* second edition published in 2021 (updated in October 2022) (*V2.2*), p.5. https://www.ea.govt.nz/documents/1875/Distribution-Pricing-Practice-Note-v-2.2-October-2022.pdf
[5] Scorecards assessments have been completed in 2019, 2020 and 2021 and are in progress for 2023.

Areas for improvement in distribution pricing

Our assessment indicates that in certain areas distribution prices are not cost-reflective and so may not lead to efficient network use or investment. For example, in general:

- time-varying pricing is not being applied comprehensively or consistently, nor is it applied in a way that provides confidence that it correctly signals the economic cost of network use
- there has been little progress in establishing price signals that reward flexibility and some regression with respect to services subject to control
- material off-peak usage charges remain common
- there is wide variation in approaches to assessing whether cost allocation is subsidy-free
- there is wide variation in connection pricing practices, a lack of transparency and some approaches that could inefficiently deter connection of new load such as public EV chargers
- many retailers are billed on deemed or residual profiles, even where properties have smart meters installed (which significantly reduces retailers' incentives to manage input costs).

If these problems are not addressed with urgency, distribution pricing will hold back the transition and/or make it more costly for consumers.

Targeting areas of focus for reform

The Authority seeks to balance several factors while considering these current concerns. We intend to ensure that pricing distortions that will hold back the transition or add significant cost to consumers (for example, by delaying the development of flexibility services), are removed as soon as possible. We know some distributors have made significant progress with their pricing reform and that progress should be acknowledged and built on. We want to avoid reform that requires distributors to re-work pricing in areas where it is already fit for purpose. Further, we would prefer to retain a level of pricing flexibility, both generally and for each distributor. We recognise the 29 networks are responding to an evolving range of challenges, some common and some network-specific. So, mandating a single comprehensive pricing methodology is unlikely to be appropriate.

The Authority is seeking to target for possible intervention the following specific areas (which are discussed in this paper):

- prices that signal the cost of network use at periods of high demand
- prices that do not distort network use during off-peak periods
- efficient allocation of shared costs between consumer groups
- consistent and efficient connection pricing (capital contributions)
- retailers' response to distribution pricing signals.

Regulatory reform options

The Authority is considering the use of Code amendments and other measures to promote faster and more consistent pricing reform. This paper explores the following options:

- a *continuation* of the Authority's current approach: pricing principles, guidance (eg, distribution pricing practice note) and distribution pricing scorecards
- *control* – mandate or prohibit (via future Code amendment) certain pricing approaches (eg, prohibit those deemed to be inefficient, distorting usage and/or investment decisions)
- *call-in* – provide (in the Code) for targeted call-in and approval by the Authority of specific aspects of a distributor's (or distributors') methodology that are outliers in some sense.

Some of the areas covered in this paper (such as time-of-use, TOU pricing) have been discussed before – although in some of these areas the Authority's thinking has evolved. Other issues (such as connection costs) are relatively new focus areas for the Authority. For all these matters, this paper is an opportunity to test with stakeholders our current thinking on the issues and on the identified regulatory reform options. We are open to others' perspectives and are interested in your views. We value feedback from stakeholders on these matters.

After we have considered stakeholders' views, the Authority will consider whether to propose any Code amendments for further consultation. We anticipate that consultation on the first proposed set of Code amendments in this area (if any) would begin in late 2023.

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1. Introduction

1.1. The purpose of this paper is to consult with interested parties on the Electricity Authority's (Authority) thinking with respect to the regulatory settings for distribution pricing and how to ensure these are best suited for promoting the Electricity Authority's statutory objective.[6]

1.2. The Authority is committed to ensuring that reform of distribution pricing occurs in a timely manner. Efficient distribution pricing can support an affordable transition to a low-emissions economy that is for the long-term benefit of consumers.

1.3. The Authority is now considering the use of Code amendments to promote faster and more consistent pricing reform in identified areas of focus. We are seeking feedback from stakeholders on these issues and on the regulatory options we are considering.

Making a submission

1.4. Our preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix G Submissions in electronic form should be emailed to distribution.pricing@ea.govt.nz with "Issues Paper—" in the subject line.

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

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

(a) indicate which part should not be published,

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

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

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

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

When to make a submission

1.9. Please deliver your submission by 5pm on Wednesday 9/08/2023.

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

1.11. There will be an opportunity to make cross-submissions. The cross-submission period will close at 5pm on Thursday 24/08/2023.

[6] The Electricity Authority's main statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. (Electricity Industry Act 2010, Section 15).

Supporting information

1.12. The following table provides links to key information that may be helpful to stakeholders in their consideration of this consultation paper.

Table 1 Key sources of information relevant to this proposal

Item	Reference
Three changes to our scorecard assessments approach - 21 December 2022 *Letter to Distributors on distribution pricing scorecards 2023-24*	Distribution pricing | Our projects | Electricity Authority (ea.govt.nz) https://www.ea.govt.nz/projects/all/distribution-pricing/
Guidance on distribution pricing and pass-through of transmission charges - 18 October 2022 • *Distribution pricing scorecards interpretation guide* • *Distribution Pricing: Practice Note Second Edition v 2.2, 2022*	Distribution pricing | Our projects | Electricity Authority (ea.govt.nz) https://www.ea.govt.nz/projects/all/distribution-pricing/
Our expectations for faster reform of distribution pricing - 19 September 2022 *Letter to distributors on distribution pricing reform*	Distribution pricing | Our projects | Electricity Authority (ea.govt.nz) https://www.ea.govt.nz/projects/all/distribution-pricing/

Purpose and structure of the issues paper

1.13. This issues paper discusses the rationale and options for targeted reform of distributors' pricing and also considers the response by retailers to changes in distribution prices.

1.14. Section 2 provides some background material and the context within which changes may take place.

1.15. Section 3 outlines three broad options for targeted regulatory reform.

1.16. Sections 4 to 8 explore the following key issues (including discussion of the application of regulatory reform options in respect of each issue):

(a) peak period price signals

(b) off-peak price signals

(c) target revenue allocation

(d) connection pricing

(e) retailer response.

Next Steps

1.17. The Authority is planning to hold an online information session for stakeholders during the consultation period. Stakeholders will have the opportunity to ask questions on key areas of interest to clarify matters discussed in this issues paper. This session will likely be held in mid to late July, well in advance of the due date for submissions.

1.18. After reviewing submissions, the Authority will consider whether to propose any Code amendments for further consultation. We anticipate that consultation on the first set of Code amendments that we propose in this area (if any) would begin in late 2023.

2. Background and Context

2.1. The energy transition will require substantial investment in distribution networks. For many distributors the investment required to support the electrification of the economy will coincide with the investment needed to rebuild aging assets that are nearing the end of their lives. Recent significant weather events such as Cyclone Gabrielle will also sharpen distributors' focus on investment to increase resilience of networks. The Decarbonisation Roadmap - Electricity Sector Delivery Roadmap [7] estimates that $22 billion is required in distribution sector investment in the 2020s to scale up physical networks and invest in smart systems to integrate distributed energy resources, (DER). A similar amount of distribution investment is also required in the two subsequent decades. This is a considerable uplift from the $7.2 billion undertaken in the eight years 2013 to 2020.[8]

2.2. Economising on these investment needs will help to make the transition more affordable for consumers. This will require influencing demand. Both load management and pricing have a role to play in economising on electrification-driven network investment. Smart management of electric vehicles (EV) and hot water have been identified as offering the greatest technical and economic potential to support efficient investment.[9]

2.3. Efficient distribution pricing will play its part in the ongoing electrification by signalling the cost consequences of network usage, while avoiding deterring usage that does not add to costs - we refer to this as 'cost-reflective pricing'. Cost-reflective pricing provides incentives to use the network (and make investment choices) that promote the long-term benefit of consumers by providing better value for money: maximising the use consumers get out of the network and/or leading to relatively lower power bills for consumers in the long term.

The Authority's role in distribution pricing reform

2.4. The Authority's main objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.[10]

2.5. The Authority is responsible for pricing for transmission and distribution services.[11] These responsibilities work in conjunction with the Commerce Commission's responsibilities for the Information Disclosure regulation for all 29 distributors and the Price-Quality Regulation for the 16 non-exempt distributors.

2.6. The Authority encourages efficient distribution network pricing, including by:

(a) setting distribution pricing principles against which the Commerce Commission requires electricity distribution businesses (distributors) to self-assess and report on alignment[12]

(b) publishing a practice note that provides more information on how to apply the principles

(c) meeting with distributors regularly to discuss their pricing

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[7] *The Future is Electric: a Decarbonisation Roadmap for New Zealand's Electricity Sector*, October 2022 Boston Consulting Group, page 118.

[8] Commerce Commission - Summary of distributors Information Disclosure data

[9] The potential benefits have been quantified at six billion dollars. This approach would also result in a further benefit of a similar quantum in rest of economy savings plus significant emissions reduction. Concept Consulting *Which Way Forward? Analysis of key choices for NZ's energy Sector* October 2022 page 47

[10] Electricity Industry Act 2010 (the Act), Section 15(1). An additional objective was introduced from 31 December 2022, to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers (Section 15(2) of the Act). The additional objective applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers (Section 15(2) of the Act).

[11] Electricity Industry Act 2010 Ss 15(1), 16(b), 32(1) and Electricity Industry Participation Code s 32(4)(b)

[12] Electricity Distribution Information Disclosure Determination 2012 s 2.4.3(2)

(d) publishing “scorecards” that provide a high-level assessment of pricing at each distributor, with scoring across strategy, planning and outcomes.

2.7. The Authority has promoted distribution pricing reform over several years. In 2019, the Authority updated the distribution pricing principles, published the first edition of the distribution pricing practice note, and established the scorecards process.

Figure 1. Distribution Pricing Principles

The 2019 Distribution pricing principles

a. Prices are to signal the economic costs of service provision, including by:
   i. being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);
   ii. reflecting the impacts of network use on economic costs;
   iii. reflecting differences in network service provided to (or by) consumers; and
   iv. encouraging efficient network alternatives.

b. Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

c. Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:
   i. reflect the economic value of services; and
   ii. enable price/quality trade-offs.

d. Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

2.8. The Authority provided guidance to distributors on application of the distribution pricing principles in 2019,[13] in the Distribution Pricing Practice note (DPPN).[14] The DPPN sets out key economic concepts and examples of the Electricity Authority’s approach to efficient cost-reflective pricing. The DPPN was updated and extended in a second edition, published in 2021. Appendices have been added to the practice note, most recently in October 2022 (V2.2), [15] to provide guidance on the pass-through of transmission charges.

2.9. This issues paper builds on the analysis and examples in the DPPN. These principles apply to all the fees, charges, and contributions that distributors collect to cover their costs. In this issues paper, we distinguish between:

(a) connection charges - the up-front payments made by access seekers,[16] those wanting to establish a new network connection (or alter an existing connection). These can include processing fees and usually include capital contributions. Some distributors require new customers to contribute to the cost of upgrading capacity beyond their immediate connection.

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[13] Distribution pricing | Electricity Authority (ea.govt.nz) refer https://www.ea.govt.nz/industry/distribution/distribution-pricing/

[14] Distribution pricing | Our projects | Electricity Authority (ea.govt.nz) found at https://www.ea.govt.nz/documents/1882/Distribution_Pricing_Practice_Note_2021_2nd_edition_-_final.pdf.

[15] https://www.ea.govt.nz/documents/1875/Distribution-Pricing-Practice-Note-v-2.2-October-2022.pdf /

[16] We use the term 'access seeker' to refer to the party seeking a network connection. This may be the end user, or a party such as a property developer.

(b) use-of-system (UOS) charges - regular (typically monthly) charges paid by retailers or end users for ongoing access to the network. These may include fixed (eg, $ per day) and variable (eg, $ per kWh) components. UOS rates are usually determined annually in advance at a level that will recover the distributor's target revenue. The target revenue covers all costs not recovered through connection charges.

2.10. The Authority's focus to date has been weighted towards promoting more cost-reflective use-of-system charges. This focus reflects that:

(a) we are approaching a period where significant investment is likely to flow into new technologies at existing homes and businesses, including as part of decarbonisation efforts. Cost-reflective use-of-system charges have a key role to play in supporting the efficiency of that investment and resulting investment in distribution networks

(b) when we updated the pricing principles in 2019, uniform usage tariffs were prevalent for smaller consumers and few distributors offered tariffs that would encourage off-peak usage or signal the cost consequences of peak usage

(c) prevalent distribution tariffs structures at the time had high usage charges, including for off-peak usage, that deters electrification and overly rewards embedded generation production at off-peak times.

2.11. To help build a shared understanding of the current context with distributors, Electricity Authority staff frequently meet with distributors to better understand their pricing approach, progress, barriers to change and views on pricing reform and on the Authority's work.

The Authority's broader role in network regulatory settings

2.12. In December 2022, the Authority released its issues paper *Updating the Regulatory Settings for Distribution Networks*.[17] The issues paper discussed the significance of new technology, especially relevant to Distributed Energy Resources and their role for the future of the electricity system in New Zealand. The paper also covered the following themes: data; market settings; agreements; capability and capacity; and standards. The paper posed questions for stakeholders on each theme.

2.13. In summary, in submissions to that issues paper there was some consensus that the key themes/areas of focus include:

(a) Access to consumption and power quality data to better see what is happening on the low voltage network – residential EV charging a key concern for many distributors.

(b) Provide space and other support for trials and/or actual deployments of non-network solutions, improve transparency around consideration of and use of non-network solutions, monitor and report progress (first look to existing regulatory monitoring) and only regulate if see issues.

(c) Strong support for a review of Part 6 of the Code and for this to include load, which aligns with the more recent conversations about public EV chargers.

2.14. This is an ongoing workstream. Using the insights gained from this consultation process, the Authority will conduct a more detailed analysis of submissions to develop a work programme addressing the issues and proposals discussed. The Authority plans to publish its work programme and will develop and publish detailed issue-by-issue proposals for further consultation with industry.

[17] Issues paper: Updating the Regulatory Settings for Distribution Networks, December 2022 see https://www.ea.govt.nz/documents/1743/Issues-paper_-Updating-the-regulatory-settings-for-distribution-networks.pdf

Role of other agencies and industry groups

2.15. The Authority works closely with other agencies, groups and associations that have an interest in distribution prices. These include the Commerce Commission (ComCom), Ministry for Business, Innovation and Employment (MBIE), Energy Efficiency and Conservation Authority (EECA), and industry groups such as Energy Networks Aotearoa (ENA), Electricity Retailers' Association of New Zealand (ERANZ) and Major Energy Users' Group (MEUG). We have met with parties seeking to connect to networks, to better understand potential connection issues that may emerge during the transition, and the role distribution pricing can play to resolve them.

2.16. The ENA, the industry association for electricity distributors, has recognised the need for pricing reform and made considerable efforts to promote pricing reform amongst its members. In 2017 a well-supported distributor working group outlined the case for change and high-level guidelines for "the first wave" of pricing reform.[18] The ENA has also made efforts to address the variation in terms and structures used by members. Pricing guidelines for electricity distributors were first published in 2017 and most recently updated in 2022.[19] The Authority would like to recognise the "industry-led" work of the ENA and distributors on distribution pricing reform.

2.17. The FlexForum, an industry-led association of organisations from 'across the electricity eco-system', is doing important work focusing on the role of flexibility in the energy transition.[20]

2.18. The Climate Change Commission's recent draft advice to the Government highlighted the critical role electricity distribution businesses have in managing peak demand and delivering services for the long-term benefit of consumers.[21]

2.19. In June, the Commerce Commission released a draft decision on its Input Methodologies, which are the rules and processes that the Commission uses to administer regulated businesses (including electricity distributors) under Part 4 of the Commerce Act. The Commission's rules and processes are relevant to the issues identified in this issues paper, including connection pricing. We will continue to work alongside Commission staff as the Authority continues to develop its thinking and progress distribution pricing reform.

Scorecards assessment of efficiency of current pricing

2.20. Since 2019 the Authority has carried out three rounds of scorecards assessment. We are currently reviewing the pricing material published by 29 distributors for the pricing year commencing 1 April 2023. This review assesses key aspects of current prices including efficiency and provides some indication of what the likely progression may be without further regulatory intervention. Some quantitative analysis has been undertaken on the pricing structures, and this is discussed in section 4.

2.21. The documents reviewed included those required by the Commerce Commission's Information Disclosure regime,[22] pricing methodologies, pricing schedules, capital

[18] ENA A Guidance Paper for Electricity Distributors on new pricing options August 2017 refer to https://www.ena.org.nz/resources/publications/document/151

[19] https://www.electricity.org.nz/resources/lines-pricing-information/document/1207

[20] In their recent submission to the Authority on the 'Regulatory settings for Distribution Networks', the FlexForum discussed valuing flexibility (and pricing flexibility) and the role of distribution and retail tariffs to provide the required commercial incentives. https://www.araake.co.nz/assets/Uploads/280223_FlexForum_Response-to-EA-on-Regulatory-Settings.pdf

[21] Climate Change Commission, 2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan April 2023 p 114 see https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/advice-for-preparation-of-emissions-reduction-plans/2023

[22] https://comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors/current-information-disclosure-requirements-for-electricity-distributors

contribution policies, pricing roadmaps requested by the Authority and other clarifying documents produced by distributors such as pricing policies.

2.22. The Authority is pleased with some of the improvements that we have observed with respect to pricing methodologies and use-of-system charges. In particular:

(a) many distributors' published pricing methodologies now provide commentary on how their approach to pricing fits with their network circumstances, and how they are planning to evolve their pricing to better promote efficient use and investment

(b) many distributors have developed time of use (TOU) pricing options for residential consumers, and at least begun the process of assigning consumers connections, Installation Control Points, (ICPs), to these tariffs.

(c) the sector is following the phase-out path for the low fixed charge (LFC) regulations,[23] – i.e., increasing fixed ($ per day) charges for low users and reducing (cents per kWh) usage charges.[24]

2.23. We recognise that there have been regulatory constraints that have hampered the timely development of efficient pricing by distributors; the LFC Regulations have been a notable impediment. Other factors that may have impacted the extent and speed of price reform are system capability (both at the distributor and retailer level), uncertainty on transmission pricing and concerns around bill shock to consumers. Further, the Authority recognises that in the past it has not focussed as much on connection costs; there is now a need for greater focus on connection costs, consistent with the role these prices will play in the energy transition.

2.24. Appendix A summarises some general observations from the 2023 scorecards assessment. Some interim observations from the 2023 review (which is not yet complete) are as follows:

(a) 23 out of 29 distributors have adopted Time-of-Use (TOU) pricing structures to differentiate the cost impact of using energy at varying times of day and/or throughout the year for residential customers

(b) 11 out of those 23 reported that their TOU plans were "mandatory". However, this was subject to a smart meter being installed and retailers having the capability to submit verified half-hour data. As these criteria were not generally met in practice our current view is that TOU pricing plans for these distributors were not effectively 'mandatory'[25].

(c) Distributors who did not offer pricing that signalled the cost of peak usage commonly stated that this was because of inadequate penetration of smart meters and/or the ability of retailers to deal with half hourly data

(d) Control of hot water cylinders is a common practice among distributors who historically offered a price benefit to consumers with controlled supply. 27 out of the 29 distributors offer tariffs for controlled appliances. However, some distributors have reduced the differential between control and uncontrolled load and indicated that the technology is coming to the end of its useful life

(e) Three distributors offered a plan for residential EV charging.

(f) There is a wide variety of methods being used by distributors for connection pricing.

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[23] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

[24] Phasing-out low fixed charge tariff regulations | Ministry of Business, Innovation & Employment (mbie.govt.nz) https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price/phasing-out-low-fixed-charge-tariff-regulations/

[25] The exception is WEL Networks which has assigned the majority of its residential customers to TOU plans and able to use consumers' TOU usage for billing of distribution services.

Key terms in distribution pricing

2.25. We adopt the following terms in this paper:

(a) target revenue – the amount of revenue that a distributor aims to recover when setting UOS charges. For non-exempt distributors the target revenue must comply with revenue control requirements set by the Commerce Commission

(b) pricing area - refers to a geographic region across which a distributor sets its UOS rates. Distributors may use one or more pricing areas, and pricing area definitions may differ for different classes of consumers. For example, pricing area definitions for large industrial or commercial consumers may differ from pricing areas for other consumers

(c) consumer group – refers to the most granular level at which a distributor allocates target revenue and sets tariffs. For example, "small non-residential consumers in the northern pricing area"[26]

(d) subsidy-free range – the range within which the target revenue for a consumer group would be above the avoidable cost of serving that consumer group and below the standalone cost of serving that consumer group

(e) avoidable cost – the costs that would have been avoided if a given consumer group did not exist. As long as target revenue allocated to a consumer group is above its (annualised) avoidable cost, other consumer groups are benefiting from sharing the network with that consumer group

(f) standalone cost – the cost that would have been incurred if a given consumer group were the only consumer group. As long as target revenue allocated to a consumer group is below its (annualised) standalone cost, that consumer group is benefiting from sharing the network with other consumer groups

(g) access seeker – a party wishing to establish a new connection to a network, or to expand the capacity of an existing connection

(h) growth levy – a connection charge that contributes to general system growth costs, as opposed to the cost of specific upgrades triggered by the access seeker.

[26] This term is also used in the information disclosure determination for distributors, where it is defined as "the category of consumer used by the EDB for the purposes of setting prices". Our usage of the term is consistent with this definition. Electricity Distribution Information DisclosureDetermination 2012.pdf (comcom.govt.nz) p 14. Refer https://comcom.govt.nz/__data/assets/pdf_file/0018/316323/Electricity-Distribution-Information-Disclosure-Determination-2012.pdf

3. Distribution pricing regulatory options

3.1. This section summarises the issues and regulatory options considered in this paper.

Targeted reform of distribution pricing

3.2. The need for more efficient distribution pricing is now increasingly urgent, due to the imminent substantial investments taking place to enable the energy transition.

3.3. While acknowledging the progress we have seen (including some notable improvements in pricing methodologies by some distributors), and the constraints, the Authority is concerned that progress toward more cost-reflective pricing is not occurring as quickly or as comprehensively as the circumstances warrant. The reasons for our current view are discussed in sections 4 to 8 (which cover the key issues the Authority is focussing on).

3.4. The Authority considers that targeted reform of distribution pricing is likely to be an effective way to ensure distribution pricing structures are cost-reflective and fit for purpose for the coming step change. A targeted approach to reform of distribution pricing identifies the most significant issues across UOS and connection charges and the range of options that could be utilised to address these specific issues.

3.5. This paper examines the following three aspects of use-of-system pricing:

(a) peak signals (section 4) – many distributors have introduced pricing structures that can support better cost-reflectivity (eg, with separate peak and off-peak rates). However, uptake is far from universal, and we have observed limited progress at ensuring peak rates are set at the right level to signal network costs or that signals are coherent and internally consistent across consumer groups and tariff types. Cost-reflective peak signals are important for encouraging optimisation between network investment and decisions by users (regarding their usage and investment choices)

(b) off-peak signals (section 5) – the opportunity cost of network usage at off-peak times is near zero, however most distributors set material usage charges for off-peak periods. This increases costs for off-peak usage and reduces the pay-off from flexibility. This affects user behaviour (eg, choosing when to charge an EV or whether to turn on a heater) and investment (eg, choosing whether to use gas or electricity for heating)

(c) target revenue allocation (section 6) – we have seen mixed evidence of distributors trying to understand and actively manage where consumer groups sit within their respective subsidy-free ranges. Actively managing allocation outcomes is important as pricing evolves, network usage evolves, and consumer group definitions evolve. Allocation can be a ‘lever’ for managing price impacts (both actual impacts, and consumer perceptions) and has a role in promoting efficient use (by limiting the burden on users most likely to ration their consumption).

3.6. This paper also considers the efficiency of connection pricing, which influences incentives for access seekers (and distributors) and determines how costs are allocated between access seekers and existing users. This is of growing importance as electrification drives a step-change in connection activity, particularly for process heat and transport. Section 7 looks at the current state of connection charges, noting the wide variation in approaches in terms of:

(a) cost burden - which costs, and what share of those costs, access seekers bear

(b) methodology - how connection charges are determined

(c) discretion - how fully the basis for charges is set out in policies.

3.7. Section 8 of this paper explores issues around how retailers respond to more cost-reflective distribution prices.

Scope of this paper excludes pricing for distributed generation

3.8. This issues paper covers distribution pricing for consumers connected to the distribution network. It does not cover distribution pricing for distributed generators. Part 6 of the Code provides rules for pricing and other (non-price) access terms for distributed generation. The Authority plans to consult separately on pricing for distributed generation, and on non-price access terms for DER (which can include distributed generation), within the next year.

Regulatory options

3.9. We are considering three options for supporting targeted reform of distribution pricing, which could be adopted independently or together. We assess the application of these options to each of the issues canvassed in this paper. The three options are:

(a) *continuation* – expand practice note and pricing scorecards. This is a continuation and extension of our existing approach that relies on information and reputational incentives. It does not require any Code amendment.

(b) *control* – mandate or prohibit pricing approaches. The Code could be amended to mandate or prohibit particular pricing approaches.

(c) *call -in* – provide for targeted call-in and approval. The Code could be amended to provide for calling-in pricing methodologies (in full or in part) for review by the Authority against requirements included in the Code.

3.10. For each issue covered in sections 4 to 8 of this issues paper we provide examples of how the options could be applied and analysis of the option in the context of that issue.

3.11. The Authority's targeted approach to distribution pricing contrasts with the more comprehensive framework for transmission pricing (which encompasses locational marginal pricing, transmission charges and settlement residual rebates). We consider this difference is appropriate, given the large number of distributors and their differences in network circumstances, current pricing approaches, and resources available to devote to pricing. Comprehensive reform of distribution pricing would be complex, disruptive, and slow compared to the more targeted approach under consideration in this issues paper.

Continuation option

3.12. The Authority reviewed the distribution pricing principles in 2019 and published a reasons paper that contained the updated principles.[27] We have since referred to these in our practice notes and in subsequent consultation papers (including this one). The Commerce Commission's information disclosure requirements require distributors to publish pricing methodologies that must include a self-assessment of how the distributor's pricing aligns with the Authority's distribution pricing principles.

3.13. The Authority published an initial practice note shortly after the 2019 reasons paper and updated the practice note in 2021.[28] At the same time (in 2019), we published a scorecard template and communicated our intended timing for the first round of scorecard reviews.

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[27] More efficient distribution network pricing – principles and practice – Decision Paper 4 June 2019 see https://www.ea.govt.nz/documents/3351/Copy_of_Distribution_pricing__More_efficient_distribution_prices__Principles_a_FLpsrrD.pdf

[28] Appendix B in Distribution pricing Practice Note second edition 2021 see https://www.ea.govt.nz/documents/1882/Distribution_Pricing_Practice_Note_2021_2nd_edition_-_final.pdf

3.14. Updates to the practice note have included addressing new issues (such as pass-through of new transmission charges), expanding on pricing theory and practice, and refining earlier material based on experience and learning to date. We note that in future we could:

(a) amend the practice note to provide or update guidance relating to any of the issues discussed in this paper. This could include expanding the scope of the practice note (eg, to cover connection pricing), providing more prescriptive and detailed guidance than before (eg, on how to estimate long-run marginal cost), or updating existing material for clarity and alignment (eg, updating our discussion of congestion)

(b) complement updates to the practice notes with refinements to our scorecards assessment process. For example, we could add new focus areas to future scorecard rounds and adjust scoring to give greater weighting to those areas.

3.15. The Authority's current approach, which has not involved any Code amendments, has worked in conjunction with the Commerce Commission enforcing the obligation to disclose self-assessments. Continuing with the Authority's current approach would involve providing information and creating reputational incentives without imposing further obligations on participants.

Control option

3.16. The Authority could amend the Code to directly intervene in pricing approaches – for example by prohibiting or mandating certain distribution pricing approaches.

3.17. Such amendments could be made at any time using the normal Code amendment processes, which are designed to ensure good regulatory practices that promote the Authority's statutory objectives. Requirements would then be subject to the same enforcement provisions as the rest of the Code, with the Authority retaining operational discretion as to how it monitors compliance.

3.18. There could be benefits from bringing the distribution pricing principles into the Code including:

(a) making the principles easier for participants and access seekers to locate, and making their status more apparent (and potentially giving them force as legal obligations)

(b) making the principles subject to Code amendment requirements, which may provide distributors, other participants, and access seekers with greater confidence regarding the robustness of the change process for the principles

(c) enabling any future options that do involve Code amendments (including those discussed in this paper) to reference the pricing principles.

3.19. Whilst putting the pricing principles into the Code could provide distributors with flexibility, there could be challenges with monitoring and enforcement, as the principles could be open to a broad range of interpretation.

3.20. Mandating or prohibiting approaches is more heavy-handed than the approach the Authority has taken to date but could nonetheless be targeted to areas where the Authority is satisfied that intervention will promote its objectives. In making any such assessment the Authority would need to consider:

(a) how prescriptive to make any obligations, how to phase them in, and how to ensure they would be relaxed or removed in future if they were no longer fit for purpose or net beneficial

(b) whether the anticipated gains from more efficient pricing would outweigh the costs of change (including administrative costs and any impacts on consumer confidence) and any downsides from limiting scope for distributors to innovate or to match practices to their circumstances.

3.21. In contrast to practice notes, this mechanism may trigger provisions in the Input Methodologies that are intended to help ensure distributors can recover any material costs imposed by changes that are imposed by the Authority.[29] This may assist to overcome barriers to change in some circumstances (that is, cost barriers).

Call-in option

3.22. There may be issues for which the control option is too blunt, and a targeted mechanism for "calling in" some aspect of a pricing methodology for review and approval would provide a better balance.[30] Such a mechanism could operate as follows:

(a) the Authority may elect to 'call in' a matter for review and approval

(b) the call-in may be targeted in terms of who it applies to, and the matters it applies to. For example, the Authority could call in:

(i) the entire pricing methodology of one or more distributors

(ii) a selected pricing matter (eg, connection fees) for all, or a subset of, distributors.

(c) once a matter is called in, affected distributors must submit their methodologies for review and approval or feedback. If the Authority provides feedback, then the distributor may amend its methodology and must re-submit for approval. If the Authority is not satisfied, then it may itself identify what amendments to the methodology are needed.

3.23. The Code would need to cover matters such as:

(a) any requirements for initiating a call-in, and operating the review and approval processes

(b) possibly dispute resolution provisions (for when a distributor disagrees with the Authority's determination).

3.24. The Code amendment could possibly also be designed to trigger (if applicable) mechanisms that assist distributors with cost recovery.

3.25. The call-in option raises a number of issues, on which the Authority welcomes submissions, including the following:

(a) whether there would be specified requirements (the distribution pricing principles themselves or particular pricing methodologies set in the Code) against which distributors' pricing methodologies are to be assessed for compliance/consistency

(b) the extent to which participants would have an interest in engaging legislative enforcement mechanisms by pursuing complaints of breach of such requirements, as opposed to looking to the Authority to monitor and enforce compliance

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[29] Under s54V(5) of the Commerce Act 2008, the Electricity Authority can ask the Commerce Commission to reconsider a price-quality path determination to take account of certain matters. Under s54V(3) those matters include a change in the Code that results in increased costs to a supplier of electricity lines services

[30] The Authority has chosen to use the term "call-in" to reflect the proactive and additional level of regulatory intervention on the part of the Authority which this option entails, where the Authority requires a distributor's pricing methodologies to be brought in and put through a designated procedure directed by the Authority. This is a process tailored to the Authority's particular regulatory context and is different and distinct from the concept of call-in in the Resource Management Act 1991 and other such contexts, which relate to statutory decision-making powers to approve certain applications or proposals being taken from one body and instead exercised by another due to their significance or other unique features.

(c) alternatively, whether a call-in mechanism should stop short of mandating compliance with the distribution pricing principles or other specified requirements, relying instead on the process of assessment, feedback, and active engagement by the Authority with distributors in order to bring relevant pricing methodologies into alignment with those principles

(d) where the call-in process does not result in the Authority approving a re-submitted pricing methodology as compliant with the distribution pricing principles or other specified requirements, and where the Authority identifies what amendments are needed for compliance, whether the Authority's powers should extend to amending the methodology itself and requiring the amended methodology to be applied

(e) the potential for distributors to be subject to different levels of regulatory treatment according to whether or not they are subjected to the call-in process and the outcome of that process

(f) the extent to which the Authority should prescribe the call-in process through tailored Code amendments, as opposed to relying on its existing monitoring and enforcement powers (including its statutory powers to require the provision of information for monitoring and enforcement purposes).

3.26. Interested stakeholders may see other issues as well, which the Authority encourages them to raise in their submissions.

Q1. Are there other options that you think the Authority should consider?

Q2. Do you have any comments on the options outlined?

4. Peak period price signals

4.1. This section of the paper discusses the need for prices during peak demand periods to signal the cost consequences of network usage, for networks that anticipate having insufficient network capacity to meet anticipated demand (anticipated congestion). This creates a payoff for avoiding peak periods (or allowing load management) that users can weigh up against the benefits of peak-time usage. This dynamic is particularly important at a time when electrification is becoming a major driver of network investment. Many distributors have introduced non-uniform usage tariffs that facilitate better peak price signals, but progress at shifting consumers to those tariffs and ensuring signals align with costs appears slower than circumstances may warrant.

Context

4.2. Relevant pricing principles are (a)(ii) and (b).

Table 2. Pricing principles relevant to peak price signals

Reference	Principle	Relevance
(a)(ii)	Prices are to signal the economic costs of service provision, including by…reflecting the impacts of network use on economic costs	Prices for peak periods (and controlled/uncontrolled differentials) should signal the cost consequences of usage.
(d)	Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	The methodology for estimating cost consequences should be disclosed, distributors should actively transition consumers to cost-reflective tariffs.

4.3. As the Authority observed in its DPPN,[31] a well-designed price signal provides a cost-reflective measure of the impact that an additional marginal unit of energy has on the network and can signal the opportunity cost of future necessary investments to accommodate increasing demand.

4.4. Cost-reflective peak signals are important for encouraging optimisation between network investment and decisions by users (regarding their usage and investment choices). With projections of over $20 billion of distribution service-related investment in each of the next three decades,[32] providing efficient signals around the cost consequences of usage is crucial for helping direct users toward lowest-cost usage and investment choices.

Distribution pricing compared to transmission pricing

4.5. There is commonality in the principles and issues for pricing of distribution and transmission services, with the demarcation between distribution and transmission more a matter of ownership than any sharp break in design or functional characteristics. For example, there is cross-over between distribution and transmission voltages, with Transpower owning several sub-110 kV lines and larger distributors owning 110 kV lines.

[31]. *Distribution Pricing Practice Note V2.2* Oct 2022 Electricity Authority (ea.govt.nz) p 6.

[32]. *The Future is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector*, October 2022 Boston Consulting Group, p 118

4.6. There are also key concepts from the TPM process that inform our thinking of distribution pricing, including the need to draw a clear distinction between:

(a) pricing components that are cost-reflective and are intended to influence usage and investment decisions. For transmission pricing, this includes locational marginal prices, connection charges and (the prospect of) benefit-based charges

(b) pricing components that are necessary to ensure full cost recovery and should be designed to avoid influencing usage and investment decisions. For transmission, this includes residual charges and (to a lesser extent) benefit-based charges (once allocated).

4.7. There are also clear differences between transmission and distribution that are relevant to pricing design. These include:

(a) distribution network flows are predominantly one-way, from the grid exit point to small radially distributed loads. This means there is less scope to improve efficiency by rationing generator access, or access by load parties – including because electricity is not a dominant input cost for most distribution customers

(b) there is limited real-time visibility of loads or flows on distribution networks

(c) in many cases, capacity can be added more incrementally than is the case for transmission networks.[33]

Distribution pricing and the changing landscape

4.8. Some of these fundamentals are expected to evolve over coming decades, notably:

(a) distributed generation is increasing, and in some networks may become a source of congestion and driver of capacity investment if there is not a method for economic rationing of generation access

(b) the number of flexibility resources is likely to increase. Most notably, household level EV charging is forecast to become a source of flexible demand comparable in scale to hot water cylinders, and vehicle-to-grid injection could further relieve network investment pressures

(c) process heat electrification will increase the number and range of distribution-connected businesses for whom electricity is a material input cost that could warrant active management

(d) a number of distributors are considering investments that would increase the visibility of loads and flows on their networks

(e) digital platforms are expanding the scope for coordinating distributed resources

(f) the scale of network build anticipated in coming networks may make it difficult for the sector to deliver capacity upgrades ahead of demand, driving a greater need to manage congestion.

4.9. These changes mean that, one day, it could be appropriate for distribution pricing to be used to signal the short-run costs of network congestion in support of a network planning approach that no longer adds capacity well ahead of demand. As noted in MIT's Utility of the Future paper:[34] "Granularity matters. The prices and regulated charges for electricity services vary significantly at different times and in different locations in electricity networks."

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[33] Transpower invested around $2 billion across a small number of major projects between 2009 and 2014, ending with a total asset value of around $4.5 billion. While this was an exceptional period, it is indicative of the potential scale of transmission investments relative to total network value.
[34] *Utility of the Future*, MIT 2016, https://energy.mit.edu/research/utlility-futurestudy/ p.132

Progressively improving the temporal and locational granularity of prices and charges can deliver increased social welfare; however, these benefits must be balanced against the costs, complexity, and potential equity concerns of implementation."

4.10. By contrast, it has, to date, been common for distributors to add capacity ahead of demand, keeping their networks congestion-free with a short-run cost of network usage that is near zero at all times. If capacity is always added in advance of congestion occurring, then the cost consequence of increasing usage is to bring forward the timing of capacity upgrades. In this case, for networks with anticipated congestion due to demand growth, it can be relatively efficient to set peak signals with reference to the long-run marginal cost (LRMC) of network capacity. As the Authority stated in its DPPN,[35] it is efficient for a distributor to use such price signals to delay the necessity of investments, until the cost of a network upgrade (or alternative solution) becomes economically justifiable - ie, the value to consumers exceeds the cost. In this way, price signals lead to efficiency in the long-term.

4.11. In this context, it can also be practical, efficient, and effective for distributors facing demand growth to use TOU pricing for small users, rather than more dynamic or targeted price signals. This reflects that the main decisions that price signals influence are investment (such as appliance or fuel choices) and set-and-forget usage decisions (such as whether to habitually shift some usage away from mornings and evenings). TOU can send an efficient signal for these types of decisions, while being comparatively effective due to their predictability and ease of understanding.

4.12. These factors mean that, at least for small users, the Authority has been comfortable with distributors facing demand growth transitioning to TOU structures as a starting point for improving cost-reflectivity. For example, the Authority stated in its DPPN, in 2021,[36] that: 'TOU tariff structures can be effective in reducing congestion on a specific part of a network during times of peak load.'

4.13. The distribution pricing practice note (second edition)[37] discussed the concept of a "window of opportunity" for price signals to influence the timing of capacity upgrades. This concept can help ensure signals are efficient by recognising the lead times and lags involved in network capacity planning and consumer response. It also points to the idea that, if a distributor is unable to add capacity ahead of demand, their approach to incentivising flexibility may have to change – for example, by purchasing flexibility and/or shifting to pricing better suited to signalling short-run costs (such as critical peak pricing).

4.14. Critical peak pricing was highlighted as a pricing option in the ENA guidelines on new pricing options published in 2017.[38] As outlined in the DPPN in 2021, critical peak pricing may be a further evolution of TOU pricing and could factor in peak events on a network or sub-networks. As noted in the DPPN:[39] 'This will amplify a price signal of an existing TOU structure, and for some networks just a 'critical peak price' may be sufficient to manage time-bound congestion, eg, the coldest winter night in a season, or rural coastal areas with a high density of holiday homes over the December/January holiday season."

4.15. The Authority considers that the optimal level of pricing granularity will change over time. In this context, we would note that TOU is an option that is available to us now. It is reasonably easily understood by most consumers and implementable – though some consumer education may be required. While, as noted in the DPPN, there are some

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[35] *Distribution Pricing Practice Note V2.2* Electricity Authority Oct 2022 (ea.govt.nz) p.8
[36] ibid, p.9
[37] Ibid, p.8
[38] Critical peak pricing is discussed in ENA *A Guidance Paper for Electricity Distributors on new pricing options* August 2017 https://www.ena.org.nz/resources/publications/document/151.
[39] *Distribution Pricing Practice Note V2.2* Electricity Authority Oct 2022 (ea.govt.nz) p.18

disadvantages in applying a TOU pricing structure across a whole network (including parts with no congestion),[40] there are also likely to be advantages in terms of simplicity and practicality. With distributors facing demand growth having now clearly moved toward TOU pricing the Authority supports TOU as the first stepping-stone in pricing reform for distributors facing future congestion, providing it can be implemented in a way that is cost reflective.

4.16. Load control is also an important method for managing congestion on networks. As noted in its recent open letter to distributors,[41] the Authority considers separate load control tariffs to be an appropriate and cost-reflective way to approach mass EV charging and hot water heating, consistent with the distribution pricing principles.[42] As the Authority stated in the DPPN:[43] "Load control for hot water heating is the common application at present and has proven to be effective for managing congestion. Envisioning a future of more widespread EVs, PV and other controllable DER means that there are opportunities for greater use of demand response. Further, flexibility in the load side – including control of hot water and EV charging - will play a key role in future in balancing fluctuations in supply of energy from intermittent renewable generation around the grid."

4.17. Load control is also a key issue for stakeholders. A recent report by NERA, commissioned by Vector, looks at the challenges and opportunities for EV charging and the options for managing the impact on the LV network – and emphasises the importance of a framework for smart managed load.[44] Some parties have raised concerns about the potential for load responding to wholesale price signals to have unintended consequences for congestion on the LV network.

4.18. Exacerbation of LV congestion might also be considered to be a risk for the introduction of TOU price differentials in distribution pricing. Some distributors use shoulder pricing as part of their TOU price structure, which might be a means to mitigate this risk.

Q3A. Do you agree that a combination of TOU tariffs and load control (appliance) tariffs would be useful for the smart management of peak demand?

Q3B. Do you consider that TOU pricing could have unintended consequences for congestion on the LV network?

Q3C.Do you consider that use of shoulder pricing as part of the TOU price structure could be an effective way to mitigate this risk? What other ways could be effective?

Current situation

4.19. Although several distributors that are facing demand growth have introduced TOU prices, they do not appear to be consistently signalling the cost of capacity expansion (or alternatively, the cost of congestion if that is a relevant cost consequence of usage). From our initial review of recent pricing materials:

(a) we are not aware of any distributors having worked through the process of aligning peak rates with a robustly developed view of the cost of network capacity specific to

[40] *Distribution Pricing Practice Note V2.2* Electricity Authority (ea.govt.nz) p.9

[41] *Open letter to distributors*, Electricity Authority,19 September 2022, p.4

[42] In accordance with the principle that prices reflect differences in service provided to consumers.

[43] *Distribution Pricing Practice Note V2.2* Electricity Authority (ea.govt.nz) p 18]

[44] See NERA Promoting efficient and affordable infrastructure to enable electrified transport February 2023 see https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/nera-report-for-vector-20230228-v1-0.pdf

each consumer group (ie, reflecting the state of the network used by that consumer group, and that group's influence on the planned timing of capacity upgrades)

(b) tariff assignment approaches vary, with opt-in or wide access to opt out both common. This means the proportion of ICPs exposed to non-uniform tariffs likely remains low

(c) there has been little progress establishing price signals that reward flexibility, and regression in some cases in the signal sent regarding the distribution network value of hot water control (the price differential between controlled and uncontrolled tariffs)

(d) we have seen limited attention paid to non-residential tariff structures and peak signals.

4.20. Concept Consulting prepared analysis across multiple distributors that:

(a) estimates the LRMC (in $ per kW per year terms) signalled by the difference between peak and off-peak rates. The estimate takes account of the TOU structure for each distributor and assumes a typical residential load profile (while taking account of variations in average per ICP consumption between distributors)

(b) estimates the LRMC implied by discounts offered for hot water control. The analysis assumes typical hot water load profiles and levels of control (ie, that average per ICP hot water demand is common across the country, and distributors are accessing a common kW of controllable peak demand in return for their discount)

(c) compares the two estimates for each distributor.

4.21. Figure 2 presents the analysis described above. Observations include:

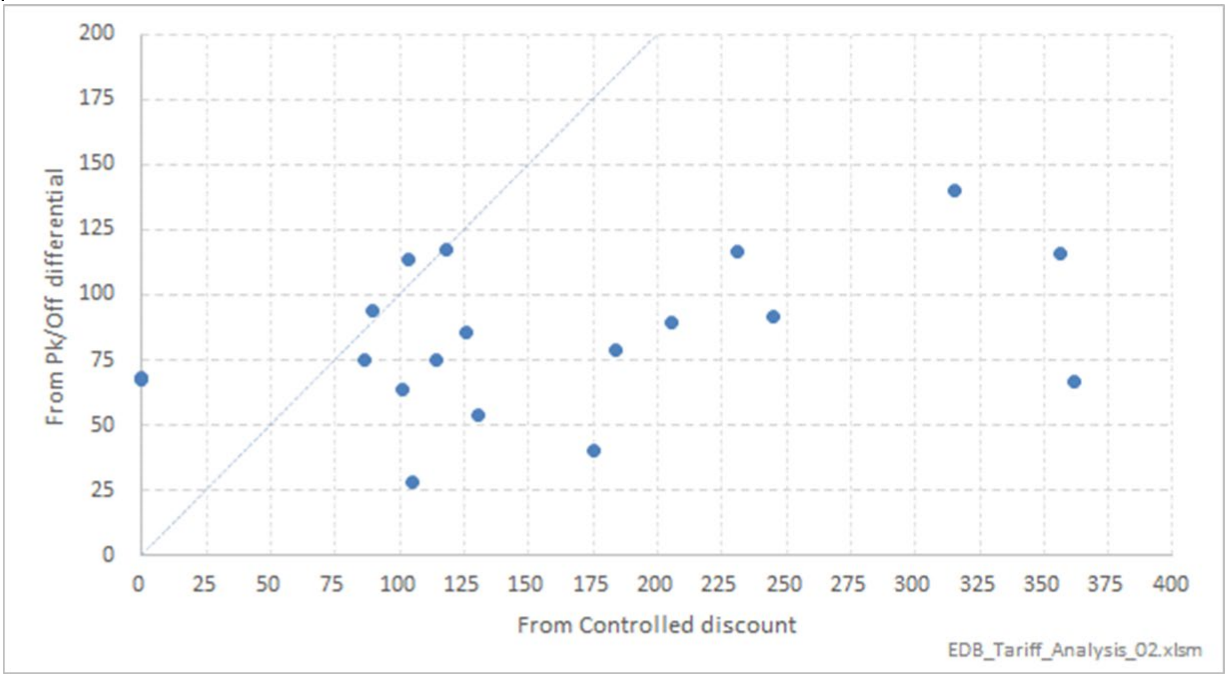
(a) there is some inconsistency *within* a distributor's tariffs between values signalled through peak/off-peak differentials and values signalled through control discounts – ie, many of the points on the chart are not close to the 45-degree line. At the extreme, one distributor signals no value from hot water control, while their Peak/Off-peak differential signals an implied LRMC of approximately $70/kW/yr

(b) there is wide variation in the implied LRMC *between* distributors. This could be justified by differences in investment pressure (ie, LRMC should be high if demand growth is bringing forward major upgrades) but we have not seen evidence of distributors making the translation in quantitative terms from their investment plans to their price signals.

(c) the average implied LRMC across the different distributors from the peak/off-peak differentials is $83/kW/yr, whereas it is $189/kW/yr from the controlled discounts.

(d) there appears to be far greater consistency between distributors as to the implied LRMC from their respective peak/off-peak differentials, than from their controlled discounts.

Figure 2: Comparison between implied LRMC signalled through controlled hot water discount and peak/off-peak TOU differential



4.22. Non-residential consumer groups are commonly defined using capacity bands, sometimes with changes in charging metrics between bands (as well as changes in rates). This can produce step-changes in pricing between bands, which can in turn influence investment decisions for new loads or electrification.

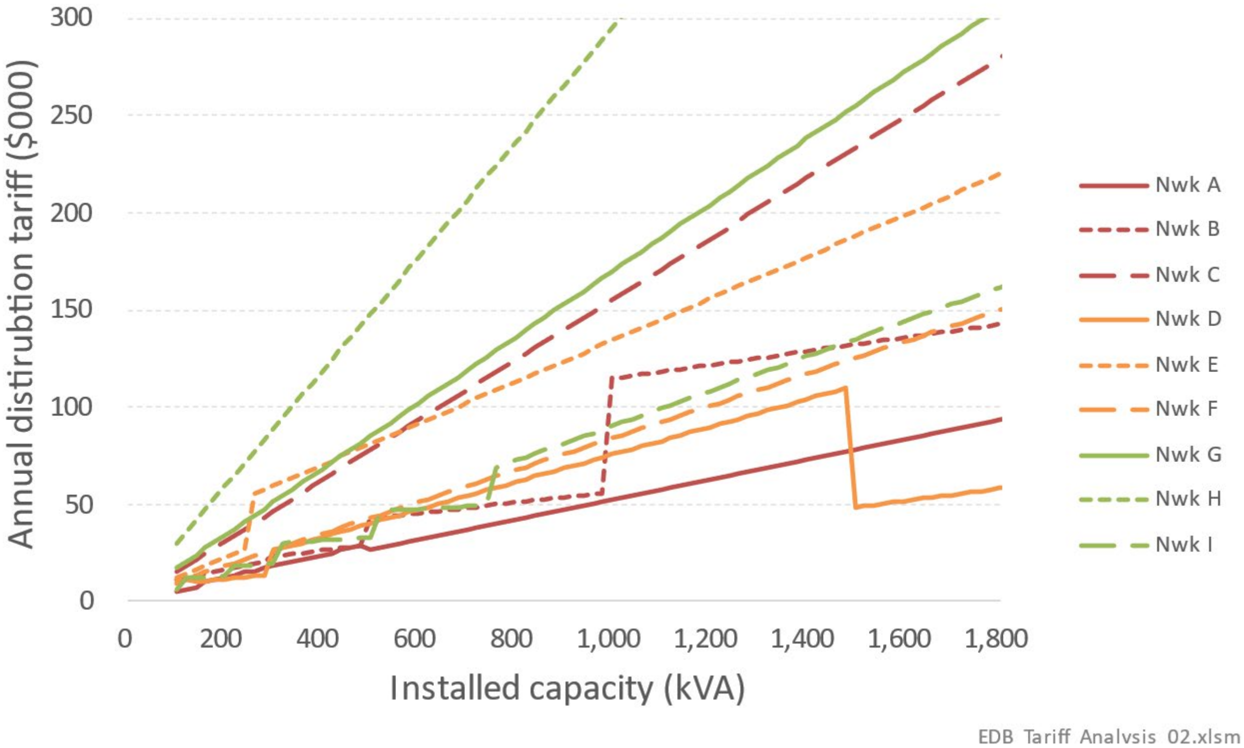
4.23. Concept Consulting reviewed a sample of distribution tariffs to see how charges vary as a function of capacity and usage for a stylised bus charging facility.

4.24. Figure 3 shows how annual tariffs vary as a function of capacity for a sample of nine distributors. This analysis is for a facility that uses energy overnight. Observations include:

(a) step changes are common, with several examples of large steps, and one example of a negative step. Steps can create inefficient price signals, as they create a high marginal cost of capacity at the step

(b) slopes vary widely between networks, indicating widely different cost-consequences of capacity. This seems unlikely to be linked to differences in actual costs between networks, so likely indicates room for some networks to improve residual cost allocation to reduce the non-cost-reflective component of the slope.

Figure 3: Capacity sizing signals for a hypothetical bus charging facility show limited coherence

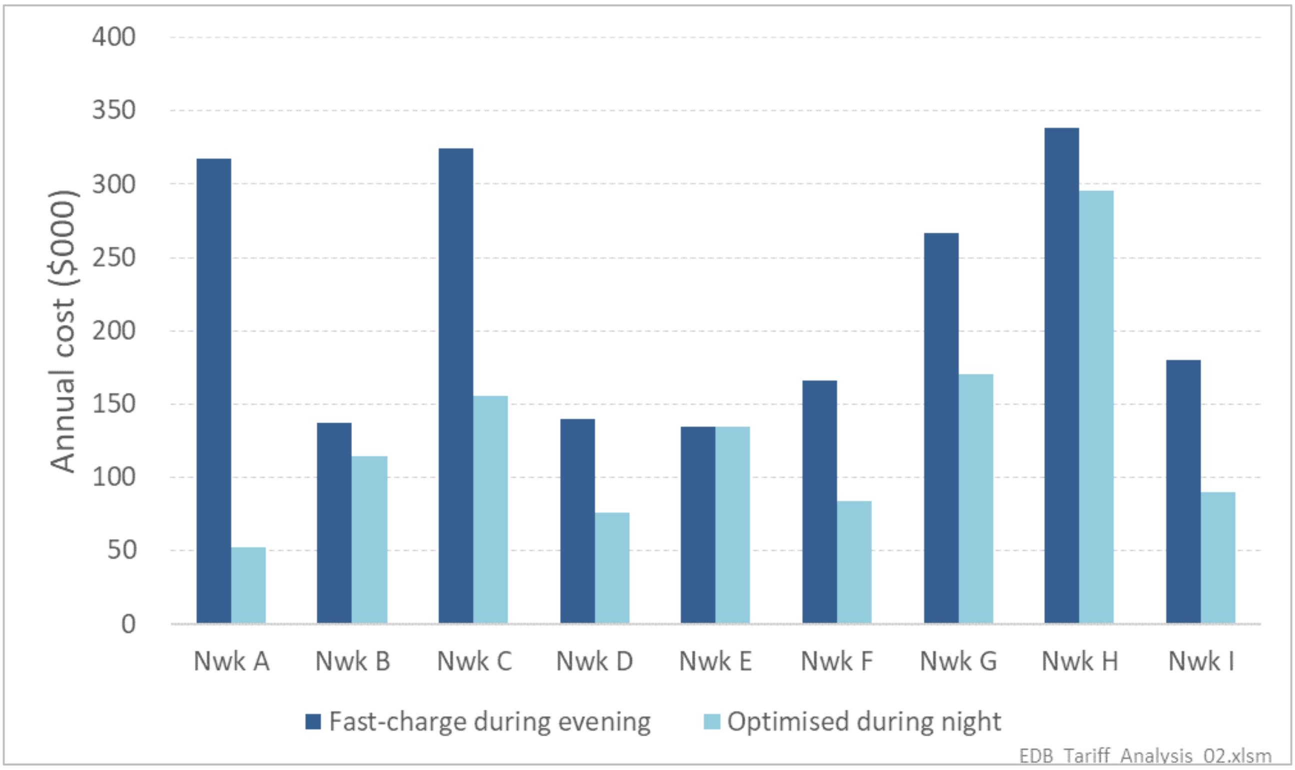


4.25. Figure 4 shows how annual tariffs vary as a function of charging behaviour for a sample of nine distributors. The analysis compares costs for a 2.6 GWh per year demand with two charging regimes – fast-charging during the evening peak, or optimised charging overnight. Observations include:

(a) one distributor provides no peak signal (ie, the bus operator does not reduce their network costs at all by charging at night). It is unlikely to be the case that there is no difference in the cost consequences of usage for that network between those two charging regimes

(b) signals vary widely across other distributors, from relatively small (Network B) to very large (Network A). Our current view is that distributors are not yet providing analysis to demonstrate that their signal strength reflects their network circumstances.

Figure 4: Peak usage signals for hypothetical bus charging facility vary widely



4.26. Some networks with a flat or falling demand and no anticipated network constraints have *not* implemented TOU tariffs. The current view of the Authority is that it is comfortable with this situation. As noted in the DPPN,[45] efficient pricing for such networks could be a fixed charge that simply recovers the invested capital without influencing network use. If recovery via a fixed charge is not available, a second-best option may be a completely flat tariff structure that does not vary by time or amount of energy consumed. Efficient recovery of residual costs in a way that does not influence consumption is discussed in section 5 of this paper. That said, an alternative view could be that network constraints should be expected to emerge on any and all networks in future, given the strain that EV charging may place on LV networks with the electrification of transport. Under this view, measures to address congestion (load control and/or TOU pricing) could be useful on all networks.

Q4. Do you agree with the assessment of the current situation and context for peak period pricing signals? What if any other significant factors should the Authority be considering?

Problem statement

4.27. Many consumers remain on uniform usage tariffs that do not send any peak price signal, even in networks with demand growth. There also appears to be little progress in establishing price signals that reward flexibility and some regression with respect to controlled hot water.

4.28. Where tariffs do send peak price signals, there is little evidence that the strength of the signal (or the price differential between controlled and uncontrolled tariffs) is tied to the cost consequences of usage through robust and transparent analysis. As a result, pricing is not sending efficient signals regarding the cost-consequences of peak usage, and this is likely to result in inefficient investment that will increase costs for all consumers.

[45] *Distribution Pricing Practice Note v2.2-October-2022* Electricity Authority Page 6.

Q5. Do you agree with the problem statement for peak period pricing signals?

Preferred pricing

4.29. The Authority's current view is that it would prefer:

(a) rapid phasing out of uniform usage tariffs for networks with anticipated congestion due to demand growth, with very limited (or zero) scope for exemption[46]

(b) rapid phasing out of deemed and residual profiles for smart meters, so that retailers are billed on actual profiles where possible and have an incentive to manage their input costs[47]

(c) differentials between peak and off-peak rates, and between uncontrolled and controlled rates, that are clearly linked to the estimated cost consequences of usage. Estimates of the cost consequences should be tailored to each consumer group

(d) platform-agnostic prices that signal the value of flexibility - for example, through access to off-peak rates for controlled appliances. These prices should not be tied exclusively to a distributor's own ripple control, and should at least cover hot water cylinders and EV wall chargers

(e) efforts to ensure signals are coherent and internally consistent across and between tariffs and consumer groups

(f) standardisation on ICP pricing – ie, pricing based on each individual consumer's consumption, rather than a retailer's aggregate consumption at a GXP (or any other point on the network). This makes pricing more consistent for retailers (ie, across networks), removes a risk of favouring larger retailers,[48] and provides better (more granular) data to distributors that can be useful for pricing design (and network planning).

4.30. The Authority is aware of the risk that changes to distribution pricing – particularly the introduction of higher prices during peak demand periods – have the potential to exacerbate energy hardship for some consumers as an unintended consequence. We acknowledge the important work the Energy Hardship Expert Panel and Energy Hardship Reference Group are undertaking in this area.[49] We will consider the potential impact of pricing reform on consumers as options are evaluated and considered in the future.

Q6. Do you have any comments on the Authority's preferred pricing for peak periods?

[46] ICPs without half-hour metering can be assigned to non-uniform tariffs and billed on residual demand profiles. This produces an equivalent outcome to maintaining uniform tariffs with their rate designed to match the equivalent non-uniform option.

[47] In section 8 Retailer Response discusses this issue.8.17 looks at the penetration of AMI meters capable to recording HH data.8.24 discussed regulatory options that may speed the transition to billing on actual half hourly data rather than profiled data.

[48] A retailer with a larger number of customers is likely to have a lower after-diversity peak demand.

[49] Energy hardship expert panel and reference group | Ministry of Business, Innovation & Employment (mbie.govt.nz) see https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-hardship/energy-hardship-expert-panel-and-reference-group/

Options

4.31. The options the Authority is considering are:

(a) do nothing. There has been progress to date, but it has been slow and not universal. While the LFC phase out may improve progress once complete, progress could have been faster even with the LFC in place

(b) refine practice note and extend scorecards. The current practice note discusses congestion at a conceptual level but does not provide practical 'how to' information. For example, we could provide demonstration methodologies or calculations for deriving LRMC estimates and converting them to tariffs, and for testing the coherence of price signals. We could also complement the practice note with demonstration workbooks. Future scorecards could be adjusted to give more weight to the robustness and efficiency of peak signals

(c) prohibit or mandate specific approaches. For example, we could:

  (i) prohibit uniform usage charges for networks with anticipated congestion due to demand growth, with exemption on application to the Authority

  (ii) mandate tariff assignment policies

  (iii) mandate analysis and disclosure of peak signal strengths (including differentials between controlled and uncontrolled tariffs)

  (iv) mandate availability of appliance tariffs, with requirements for their structure and eligibility criteria

  (v) mandate use of actual half-hour data for all smart meters

  (vi) prohibit GXP pricing

(d) call-in peak pricing for review and approval, either for specific distributors or across the board.

Q7. Are there other options you think the Authority should consider for improving peak period pricing?

Analysis of options

4.32. An option is to refine the practice note, increase focus at the next scorecard round, and introduce control and call-in as backstops to reinforce incentives for progress.

4.33. Our experience to date is that practice notes and scorecards alone produce inconsistent progress across the sector, and we expect this would remain true for peak signals even with clearer guidance and more scorecard focus.

4.34. Control could have a role to play, either as a blanket requirement (like no GXP pricing) or with exemptions to allow for outliers (like prohibiting uniform usage charges).

4.35. Because pricing changes usually need a transition, including to manage customer impact, control would often need to be implemented with a transition path or transition period (for example, a number of years between the decision to control and control being in force).

4.36. In other cases, control would be dependent on other enabling steps. For example, appliance tariffs work in conjunction with eligibility criteria (ie, enrolment with which services is needed to access to the discounted price) and service standards (ie, access to how many hours of control during which time periods is needed to access to the discounted price).

4.37. Targeted call-in could provide an alternative means to address peak signalling - either by targeting high risk distributors or by calling-in aspects of peak signalling (such as cost-consequence methodologies) across all distributors. Call-in provides more scope to tailor approaches to each network but could be slower and more costly to apply. It can be difficult to treat peak signalling as a separable component of pricing, so call-in of high-risk distributors may be a more useful approach – where risk is assessed in terms of potential from consumer harm (eg, because signals appear poor and forecast demand growth or network investment is high).

Q8. Which if any of the above options do you consider would best support distribution pricing reform around peak pricing signals and why?

5. Off-peak price signals

5.1. This section of the paper discusses the problems that arise due to most distributors setting material usage charges for off-peak periods – even though the cost of network usage at off-peak times is typically near zero. This deters efficient usage, reduces the cost advantage of key electrification technologies, and risks over-stimulating off-peak generation.

Context

5.2. Relevant pricing principles are (a)(ii) and (b).

Table 3. Pricing principles relevant to off-peak price signals

Reference	Principle	Relevance
(a)(ii)	Prices are to signal the economic costs of service provision, including by…reflecting the impacts of network use on economic costs	The cost consequence of usage at off peak times is typically near zero.
(b)	Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.	Volume charges are more likely to inefficiently influence network use than alternatives such as fixed ($ per day) charges.

5.3. The pricing principles are consistent with a three-step approach to developing use-of-system charges:[50]

(a) allocate target revenue to pricing areas and then consumer groups

(b) set cost-reflective peak charges designed to influence network usage. For example, these could include the peak component of a time-of-use tariff ($ per peak period kWh), or a more targeted or dynamic peak charge (eg, $ per peak period kW)

(c) set residual charges designed to close the gap between revenue from peak charges, and the target revenue for the consumer group. Residual charges should be designed to avoid influencing network usage.

5.4. The portion of target revenue recovered through peak charges depends on the level of investment pressure - as capacity tightens, cost recovery should shift from residual to peak charges (and vice versa) without necessarily altering target revenue for each consumer group.

5.5. Residual costs are typically recovered through a mix of:

(a) off-peak usage charge ($ per off-peak kWh)

(b) fixed charge (eg, $ per day or $ per day per connection kVA).

5.6. Of these options, fixed charges are preferable. Usage-based charges for off-peak periods signal a cost to the user that is higher than the cost consequences of usage. This can inefficiently deter off-peak usage, over-reward off-peak load reduction, and under-reward

[50] This approach was set out in Figure 1 of the DPPN V2.2. p.5 *Distribution Pricing Practice Note v2.2-October-2022* Electricity Authority

load shifting. Examples of inefficient decisions from non-cost-reflective pricing for off-peak use include:

(a) raising the cost of overnight or midday EV charging, which reduces the running cost advantage of EVs relative to internal combustion engine (ICE) vehicles, and misses an opportunity to reward efficient charging habits

(b) raising the cost of electric hot water and space heating, which reduces the cost advantage relative to gas

(c) reducing the pay-off for shifting demand from peak to off-peak, which reduces the value of flexibility and misses an opportunity to encourage efficient appliance usage habits

(d) raising the payoff for embedded generation that produces energy at off-peak times, which can over-stimulate investment in such generation and shift cost recovery to customers without embedded generation.

5.7. A small off-peak usage charge would be appropriate if there were material network cost consequences from off-peak usage. In practice, any cost consequences are typically negligible as marginal losses are low on lightly loaded equipment,[51] and changes in off-peak usage won't (by definition) impact network capacity upgrade plans.

5.8. We note that zero charges for off-peak network usage does not imply free usage because network users pay:

(a) a fixed charge for access to the network, and

(b) for their use of energy (which usually has a non-zero price or is bundled into a non-zero retail price).

5.9. The Authority noted the importance of recovering residual revenue in a way that does not distort network use in its DPPN in 2021,[52] in the extension to the DPPN to cover transmission pricing pass-through in 2022, and in its recent open letter to distributors.[53] In the open letter, the Authority encouraged distributors to increase their use of fixed charges to match the phase-out path of the LFC regulations and to avoid, or transition away from, recovery of costs that are fixed in nature through use-based charges, such as charges based on a customer's Anytime Maximum Demand (AMD).

Current Situation

5.10. Material off-peak usage charges remain common, with reasons including:

(a) continued availability of legacy tariff structures with uniform usage charges (that don't vary by time of day)

(b) compliance with LFC regulations, which apply a cap to fixed charges for residential consumers. This can create a shortfall that distributors may choose to recover from off-peak usage charges, or an uplift to peak and off-peak charges (to preserve a cost-reflective differential between peak and off-peak) - noting this outcome could be avoided or mitigated by allocating less target revenue to residential consumers.

5.11. The Authority recognises that off-peak usage charges have a different distributional impact to fixed charges, such that distributors must consider bill impact as they rebalance toward

[51] Marginal losses can even be negative on lightly loaded equipment. Transformers have standing losses, so the loss per unit of energy decreases with increasing demand when lightly loaded. This phenomenon produces negative settlement residue on the transmission system

[52] *Distribution Pricing Practice Note V2.2,* Electricity Authority, (ea.govt.nz) p. 20

[53] *Open letter to distributors,* Electricity Authority, 19 September 2022

fixed charges. In addition, off peak usage charges have been 'normal' for decades and are familiar to distributors and consumers alike.

5.12. In addition, distributors may be hesitant to fully rebalance from variable to fixed if they do not have a robust understanding of subsidy-free ranges.

5.13. Notwithstanding the points above, reducing off-peak charges is an important part of the move to more cost-reflective pricing with important impacts on investment incentives for technologies that matter for efficient electrification, such as transport, hot water heating, process heat, renewable generation, and flexibility resources.

5.14. We continue to see some distributors using an individual customer's AMD (customer AMD) as a charging metric to recover residual costs. Some distributors have argued this charging metric is less distortionary than using a measure of capacity as a basis for fixed charges.

5.15. Many distributors apply fixed, capacity-based, charges to commercial consumers of varying sizes by allocating consumers to relatively narrow capacity bands or by applying a $/kVa charge to a measure of installed capacity.

Q9. Do you agree with the assessment of the current situation and context for off-peak pricing signals? What if any other significant factors should the Authority be considering?

Problem statement

5.16. Material charges for off-peak usage remain common, which deters efficient usage and sends inefficient investment signals for technologies that matter for efficient electrification.

Q10. Do you agree with the problem statement for off-peak pricing signals?

Preferred pricing

5.17. The Authority prefers very low or zero charges for off-peak usage, with residual cost recovery achieved through use of fixed charges and active management of the allocation of target revenue between consumer groups.

5.18. Notwithstanding this preference, the Authority expects distributors to:

(a) be aware of distributional impacts and to manage the transition from legacy tariffs

(b) develop a robust understanding of subsidy-free ranges for their consumer groups to inform their management of target revenue allocation.

5.19. The Authority's view is that distributors should not use customer AMD as a charging metric to recover residual costs. We consider that use of customer AMD, particularly when the chargeable quantity is a single annual peak updated each year, provides a strong incentive for customers to reduce their peak load, and potentially invest in technology that lops their peaks. Where there is no congestion or the customer's peak does not coincide with network peak (so reduction does not impact on network costs), such behaviour is inefficient and shifts costs to other consumers.

5.20. We would be interested in any data that sheds light on the question of which allocation metric is more or less distortionary. We would also be interested in distributors outlining any relevant experience in this area on how they overcome challenges and applied non-distortionary fixed charges to a wide range of commercial consumers on their networks.

5.21. The Authority prefers that distributors pass transmission charges through to their own customers in accordance with the guidance on pass-through of transmission charges that the Authority released in 2022.[54]

Q11. Do you have any comments on the Authority's preferred pricing for off-peak usage?

Options

5.22. The options the Authority is considering are:

(a) do nothing. There is evidence of distributors gradually rebalancing away from off-peak usage charges, including in line with the phase-out path for LFC regulations

(b) extend practice note and score cards to address off-peak price signals. This topic has been covered already, but the Authority could refine its advice to make it clearer and more definitive

(c) prohibit or mandate specific approaches. For example, we could prohibit uniform usage charges (with narrow exemption criteria), set a cap on off-peak usage charges, and prohibit use of customer anytime maximum demand (AMD) as a charging metric[55]

(d) call-in off-peak pricing for review and approval, either for specific distributors or across the board.

Q12. Are there other options you think the Authority should consider for improving off-peak pricing?

Analysis of options

5.23. Our preferred approach is to sharpen our practice note, increase focus on off-peak pricing at our next scorecard assessment round, and introduce control and call-in backstops to reinforce incentives for progress.

5.24. Our experience to date is that practice notes and scorecards alone produce inconsistent progress across the sector, and we expect this would remain true for off-peak charges even with clearer guidance and more scorecard focus.

5.25. The option to prohibit uniform usage charges, other than where narrow exemption criteria apply (such as no communicating smart meter or declining demand on a network) could make a significant difference to off peak usage charges overall. Advantages of this approach could include:

(a) consistency across all retail markets, providing greater impetus and clarity for retailers. Retailers typically trade across multiple networks and often prefer a nationwide approach that simplifies their billing, marketing, and customer management

(b) regulatory validation of pricing changes that distributors may feel uncomfortable defending without endorsement from a regulator.

5.26. A descending cap (ie, a cap that reduces each year) on off-peak usage charges could be a suitable complementary measure, providing similar benefits in terms of clear and consistent

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[54] *Distribution Pricing Practice Note V2.2,* Electricity Authority, (ea.govt.nz)
[55] Note that using an individual customer's AMD as a charging metric deters usage at any time, including off-peak periods. This is distinct from using aggregate consumer group AMD as a target revenue allocator, which does not have the same impact on usage incentives (provided no individual user has too much influence on the consumer group outcome).

requirements with regulatory validation. A descending cap approach provides scope for distributors to manage bill shock, including through gradual changes and active management of target revenue allocation.

5.27. Targeted call-in could provide an alternative means to address off-peak charging - either by targeting poor performers or by calling-in off-peak charging across all distributors. Call-in provides more scope to tailor approaches to each network but could be slower and more costly to apply. It is less clear that call-in would have a role to play in off-peak charges but could be used to address the related issue of target revenue allocation.

Q13. Which if any of the above options do you consider would best support distribution pricing reform around off-peak pricing signals and why?

6. Target revenue allocation

6.1. This section covers the first step in the pricing process, which is to allocate target revenue to pricing areas (if applicable) and then between consumer groups. Allocations should be subsidy-free and actively managed to minimise harm and promote efficiency. There is limited evidence of robust subsidy-free analysis or active, purposeful management of allocations, and some evidence that an inefficiently high allocation may be placed on residential consumer groups. This is a relatively new area of focus for the Authority.

Context

6.2. Relevant pricing principles are (a)(i), (b) and (d).

Table 4. Pricing principles relevant to target revenue allocation

Reference	Principle	Relevance
(a)(i)	Prices are to signal the economic costs of service provision, including by…being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs)	Target revenue allocated to each consumer group should be tested to ensure it is within the subsidy-free range
(b)	Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use	Active management of target revenue allocation can reduce inefficient rationing.
(d)	Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	Active management of target revenue allocation can mitigate consumer impacts.

6.3. The pricing principles are consistent with a three-step approach to developing use-of-system charges:

(a) allocate target revenue - first to pricing areas (if applicable) and then to consumer groups

(b) set cost-reflective peak charges designed to influence network usage

(c) set residual charges designed to close the gap between revenue from peak charges, and the target revenue for the consumer group. Residual charges should be designed to avoid influencing network usage.

6.4. The first step involves allocating target revenue - ie, the amount the distributor aims to recover for the year to ensure they recover their efficient costs - to consumer groups. This is a one-step process for distributors with a single pricing area (ie, common pricing across their network). For distributors who set different prices in different parts of their network, there is a two-step process of allocating to pricing areas and then consumer groups.

6.5. Allocating to pricing areas typically involves two parts:

(a) direct attribution - revenue relating to assets (and potentially some operating costs) used by a single pricing area can be directly attributed to that pricing area.[56] For example, regulatory asset base (RAB) values can be used to allocate asset-related revenues between pricing areas

[56] Transmission costs can also be directly attributed in cases where GXPs map to a single pricing area.

(b) common cost allocation - revenue relating to shared assets and common operating costs can be allocated between pricing areas using suitable allocation metrics.[57]

6.6. The process outlined above for allocating target revenue between pricing areas is an accounting-based approach - it uses accounting measures of asset values and operating costs to achieve a cost-reflective allocation between geographic areas. This approach is logical and transparent because a large share of costs are clearly attributable to a single pricing area, and it should always produce a subsidy-free result with respect to pricing areas (ie, each pricing area should benefit from the existence of the other pricing areas).

6.7. Many distributors also use an accounting-based approach for allocating target revenue to consumer groups - typically using 'cost of supply' or COSM models. In this case:

(a) some costs are readily and clearly attributable - for example, low-voltage assets are not used by consumer groups that connect at medium or high voltage; but

(b) most costs are not clearly attributable and are instead allocated using a selection of allocation metrics.

6.8. Using an accounting-based approach for allocation to consumer groups results in relatively complex models that are difficult for consumers to understand and make it difficult for distributors to adopt a more purposive approach to allocation.

6.9. A purposive approach prioritises consumer impact and efficiency outcomes, including:

(a) managing allocations within subsidy-free ranges

(b) within those ranges, weighting allocations towards consumer groups least likely to ration their usage (as this promotes an efficient allocation)

(c) softening bill impacts as prices are restructured (for example, from uniform to peak and from usage-based to fixed)

(d) supporting predictability, including by rebalancing allocations gradually.

6.10. The Authority's October 2022 guidance on pass-through of transmission charges recommended a proportionate approach to allocation, with a preference for consumer group GWh as an allocation metric (in most cases) rather than more complex approaches that would attempt to mimic Transpower's pricing.[58]

Current situation

6.11. The Authority has not seen evidence of distributors adopting a purposive approach to allocating target revenue between consumer groups. In particular:

(a) there is wide variation in approaches to assessing whether cost allocation is subsidy-free:

(i) some distributors take a short-run view of avoidable costs, considering only avoidable operating costs. Such costs are typically negligible and do not set a meaningful lower bound on cost allocation

(ii) some distributors only consider non-network solutions when applying the standalone cost test. This can be appropriate when assessing prudent discounts,

[57] We note that allocation between pricing areas was a topical issue for Aurora's customised price-quality path. The Authority reviewed Aurora's pricing area allocation model and provided recommendations on attribution and allocation, which Aurora has since implemented as documented in their pricing methodology.

[58] The Authority notes MEUG's argument that residual transmission charges could be allocated more consistently with Transpower's pricing, relying on historical AMD. This would generally result in lower allocations to large industrial consumer groups and higher allocations to residential and small non-residential consumer groups.

but not for guiding target revenue allocation. This approach tends to set a standalone cost that is too high to be meaningful

(iii) some distributors apply the subsidy-free test per-connection, rather than at the level of consumer groups. This results in a very wide subsidy-free range, which is not a meaningful for testing allocation of target revenue to consumer groups.

(b) due to the above, most distributors do not have a clear view of how allocations to consumer groups sit within the subsidy-free range, which limits their ability to take a purposive approach

(c) most distributors use an accounting-based approach to allocating between consumer groups. This approach is unhelpfully complex and opaque, and does not support a purposive approach

(d) there has been limited evidence of change in practices since the principles were amended.

6.12. The 2019 Electricity Price Review analysed allocation outcomes, and found evidence of:

(a) a trend toward allocating an increasing share of the network cost recovery burden to residential consumers over time

(b) most distributors having allocations by 2017 that place residential consumers in the upper portion of the subsidy-free range and business consumers in the lower portion of the range.[59]

6.13. Our current view is that there is little evidence of any reversal in this trend. Appendix E revisits the Electricity Price Review findings on distribution pricing – including with respect to allocation – and how these are addressed in this paper.

6.14. The Authority's guidance on pass-through of transmission charges is also potentially relevant to the subject of cost allocation between customer groups. For example, MEUG submitted to Wellington Electricity on its recent pricing round in December 2022. MEUG expressed concern as to the approach used to allocate transmission charges to consumer groups based on kWh and its impact on their members.[60]

MEUG submits that approach is not reasonable and WE can and should implement a methodology that better reflects the intent of the TPM that has a two-step mechanism using AMD, or a proxy for AMD, as an initial allocator with subsequent annual updates using lagged energy use.*

This is a material issue. Residual charges for WE are estimated to be $30.5m for the year starting 1 April 2023, being 64% of total transmission charges.2 It is likely the proposed allocation of residual charges is a primary reason for the expected change to WE* total average line charges for residential to decrease by 11% and for commercial prices to increase by 3%.*

6.15. This example illustrates the significant impact that distributors' approach to cost allocation can have on customers – including major commercial and industrial customers. It also indicates the potential for tension between different objectives for cost allocation.

6.16. On the other hand, overly high allocations to residential consumers could lead to poor efficiency outcomes. Efficiency considerations relating to target revenue allocation include:

(a) many households are budget-constrained and will ration energy use if their monthly bill is too high - typically by under-heating their homes (noting that it is more efficient to recover fixed costs in a way that does not lead consumers to alter their network use)

[59] See EPR technical paper, pp 9-16. 4334-electricity-price-review-first report-technical-paper (mbie.govt.nz) https://www.mbie.govt.nz/dmsdocument/4334-electricity-price-review-first-report-technical-paper
[60] MEUG *Submission to Wellington Electricity Future Pricing Consultation* 16 Dec 2022 https tbc

(b) for most business, electricity is a competitively neutral input cost and in workably competitive markets will be passed through in prices provided year-to-year movements are not too large

(c) some large businesses may be more sensitive to electricity input costs. This applies where electricity is a material input cost and the business competes with other businesses that do not face the same price level for electricity - eg, because they are overseas. Such businesses are commonly referred to as energy-intensive and trade-exposed, and their competitiveness may be harmed by higher network costs

(d) some very large businesses may have the option of connecting to the transmission network instead of the distribution network. Overly high allocation of shared costs to such businesses could prompt inefficient connection behaviour, though prudent discount policies can be used to address this risk on a case-by-case basis

(e) electrification could be deterred by higher allocations, though this is unlikely provided residual costs are recovered through fixed charges and provided the change in fixed costs as a function of connection capacity is not inefficiently high.[61] If prices are well structured, then this should promote electrification because the bill impact of increasing usage should be smaller than is typically the case with legacy tariff designs.

6.17. The Authority acknowledges that it has not yet provided extensive guidance to distributors on cost allocation, and that distributors have been more focussed on the structure of usage charges than on changes to allocation between consumer groups. However, cost allocation is important including because it impacts on efficiency and because:

(a) as pricing evolves, cost allocations will naturally shift - including within and between consumer groups

(b) shifting revenue from off-peak usage charges to fixed charges alters allocation within a consumer group, and active management of allocation to consumer groups is one way of managing bill impacts

(c) creating a new consumer group rebalances allocations across consumer groups.

6.18. Consumer groups themselves are evolving due to electrification and new technologies, such that allocations, or the impact of allocations on usage, is changing regardless of whether distributors are evolving their pricing.

6.19. In principle, pricing is most efficient if costs are allocated to parties least likely to alter their usage or investment decisions as a result (i.e., to the least cost-sensitive consumers). While this principle is clear, it is challenging for individual distributors to take a position on what this should imply for allocation – for example, between residential versus non-residential consumers.

6.20. Cost allocation can have a large bearing on consumer perceptions of whether prices are equitable. The quality of information about subsidy-free ranges and about the rationale for allocation within that range can impact consumer acceptance of pricing and pricing change.

Q14. Do you agree with the assessment of the current situation and context for target revenue allocation? What if any other significant factors should the Authority be considering?

Problem statement

6.21. Allocation of target revenue between consumer groups is an important part of the pricing process that should be actively and purposefully managed to promote efficiency. This

[61] Many distributors define non-residential consumer groups using capacity bands, which can result in step changes in fixed charges (or changes in price structure) for users who increase their connection capacity from one band to another.

requires a clear understanding of subsidy-free ranges and would be aided by a move away from complex accounting cost models. There is little evidence of distributors addressing these issues.

Q15. Do you agree with the problem statement for target revenue allocation?

Preferred pricing

6.22. The Authority's current view is that it would prefer to see:

(a) application of accounting cost allocation approaches limited to allocating target revenue between pricing areas, and between voltage levels.[62] These are cases where there is relatively clear asset attribution

(b) simpler metrics, such as consumer group energy consumption (GWh) or where appropriate, consumer group anytime maximum demand (AMD),[63] used for initial allocation of target revenue (by voltage) to consumer groups[64]

(c) robust subsidy-free range estimates for each consumer group, with methodologies that take a long-run view of asset and operating costs

(d) consideration of positions within subsidy-free ranges and customer impacts and responses used to manage fine-tuning of allocations between consumer groups, both actively and transparently, with the aim of promoting efficiency by least influencing usage decisions

(e) testing of the efficiency of any signals created by relativities between consumer groups - for example, where there are step changes in prices as a function of connection size.

Q16. Do you have any comments on the Authority's preferred pricing approach?

Options

6.23. The options the Authority is considering are:

(a) do nothing. Our recent guidance on transmission charge pass-through and our discussion in this paper could begin to prompt some movement in thinking across the sector.

(b) extend practice note and scorecards. We could introduce guidance to the practice note (building in the discussion above) and make revenue allocation a focus area for future scorecard rounds. For example, guidance could cover matters such as methodologies for assessing subsidy-free ranges, the purpose of revenue allocation, the process of making initial allocations and refining them, testing relativities

(c) prohibit or mandate specific approaches. For example, we could specify allocation metrics (such as consumer group GWh or AMD), subsidy-free range methodologies, proscribe considerations that must be documented, require distributors to have a

[62] At least separating low voltage from other voltages.
[63] Note the distinction between consumer group AMD (which can be acceptable in some circumstances) and customer AMD (which the Authority discourages).
[64] We note that these metrics can produce different distributional outcomes, with AMD producing higher charges for small consumers (with peakier demand) and GWh producing higher charges for large customers (eg, with 24/7 operations). The Authority adopted a blended approach for residual transmission costs involving a historical measurement initially (updated over time with a lag), which MEUG have argued should be mirrored for transmission charge pass-through. Ofgem settled on GWh following targeted review of residual charge options that considered efficiency, fairness, and practicality.
https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/full_decision_doc_updated.pdf

residential consumer group,[65] and set bounds on allocation outcomes (for example, the ratio between residential and small non-residential prices)

(d) call-in target revenue allocation for review and approval, either specific distributors or across the board.

Q17. Are there other options you think the Authority should consider for improving target revenue allocation?

Analysis of options

6.24. An option is to update our practice note and introduce control and call-in backstops to reinforce incentives for progress.

6.25. Our experience to date is that distributors have been reluctant to depart from their traditional approach to allocating target revenue. This is understandable given its familiarity and given the relationship management challenges of rebalancing allocations. Accounting-based models also give the impression of a robust approach and defensible approach, even if they do not best support efficiency. This approach would also allow the Authority to fully explore the range of views and undertake though analysis on the efficiency consideration inherent with cost allocation approaches.

6.26. We think distributors would benefit from more support from the Authority - both in the form of technical guidance and through the moral backing and relationship management support that regulatory guidance can provide.

6.27. As such, an updated practice note may help more progressive distributors to make changes. However, we expect that backstops will help encourage progress against the tougher aspect of allocation changes and will help motivate distributors who may otherwise remain reluctant.

6.28. Some distributors may also welcome regulatory control of some aspects of allocation because it would remove much of the relationship management difficulty of changing allocations. However, control can be a blunt tool and allocation decisions can be nuanced and situation specific. As such, call-in may be a valuable complementary tool.

Q18. Which if any of the above options do you consider would best support distribution pricing reform around targeted revenue allocation?

[65] Some distributors have a single consumer group encompassing residential and small non-residential consumers. This does not facilitate a purposive approach to allocation, because residential consumers respond differently to price levels than non-residential consumers.

7. Connection pricing

7.1. This section addresses connection pricing methodologies, which determine the up-front cost for access seekers to connect to an electricity network. These are known as capital contributions.[66] Any connection costs not recovered from capital contributions are recovered over time generally through on-going distribution tariffs. With a step change in connection activity underway, it is important that connection pricing encourages efficient investment by access seekers and distributors - including through the incentives and transaction costs it creates. There is evidence of a wide variation in pricing approaches, with scope to improve incentives and reduce transaction costs.

Context

7.2. All our pricing principles described in section 2 are relevant to connection pricing.

7.3. Connection pricing refers to the up-front payments an access seeker makes to connect to a network (or alter an existing connection). Payments may include:

(a) fees, which contribute to administrative costs

(b) capital contributions, which are an up-front payment toward the cost of:

(i) dedicated assets (for use by the access seeker alone) that will be owned by the distributor

(ii) necessary modifications or upgrades of shared assets (that serve other customers as well as the access seeker), or

(iii) system growth investment more generally (ie, any investment for which the primary driver is to add capacity)

(c) repayments, if a distributor offers vendor financing for capital contributions.[67]

7.4. Regulatory allowances and regulatory asset bases for exempt and non-exempt distributors are net of capital contributions. This means capital contributions fall outside of the Commerce Commission's efficiency incentives.

7.5. Connection charges are becoming more important due to the growing volume of activity from access seekers, including relatively new types of access seeker. Notably:

(a) as EV sales ramp up, there is growing demand for a wide range of public charging facilities. We discuss public EV chargers as an example of a key technology in Appendix C – and in a box at the end of this chapter

(b) electrification of public transport, including buses and ferries, also drives connection activity – especially for metro areas

(c) electrification of freight and other private transport fleets also contributes to connection demand, including new connections and upgrades to existing connections

(d) process heat electrification is increasingly driving connection activity, from relatively small but high-volume through to very large capacity upgrades

[66] Electricity-distribution-services-input-methodologies-determination-2012-consolidated-20-May-2020-20-May-2020.pdf (comcom.govt.nz) Page 16

[67] We are not aware of distributors offering vendor financing in practice, but Transpower has offered low-cost vendor financing for new grid connections that allows access seekers to spread their up-front costs over several years.

(e) increased urban housing development arising from population growth is also promoting greater numbers of connections from access seekers.[68]

7.6. The growing importance of connection costs as an issue for decarbonisation has been recognised by the Climate Change Commission: [69]

> *The electricity system must be able to support the additional pressure that will come from industrial conversion to electricity. Decarbonisation projects occur on a much shorter timeline than EDBs are used to or the regulatory system can easily allow for. There can also be first mover disadvantage if the project triggers a network upgrade, and the company is required to disproportionally bear the costs of that. EDB resources and systems also vary significantly around the country, and they may be understaffed to facilitate large decarbonisation projects resulting in demand peaks. This can often lead to project delays due to time taken for network upgrade and projects not proceeding because the network cost is too great to justify the project.*

7.7. The context presents new challenges for distributors, including:

(a) a step change in the volume of connection requests, and the rate of demand growth

(b) opportunities to optimise system growth investment by building ahead of demand, especially for investments to support public transport and process heat

(c) a changing profile of access seekers. For example, network connection lead times, costs, and uncertainties can be disproportionately challenging for public EV charging facilities, and process electrification can introduce large step changes in demand with opportunities to optimise cost vs. reliability[70]

(d) pressure on regulatory allowances, which can be eased by increasing capital contributions. Heavier reliance on capital contributions also reduces forecasting risk, which is where a distributor may under-recover its costs because its allowances were based on forecasts that were too low.

7.8. Connection pricing arrangements are important, including because they affect:

(a) allocation of costs between access seekers and existing network users. Costs that are not recovered from access seekers are recovered through use-of-system charges. Connection pricing can result in disproportionate costs falling on access seekers or existing users, and either outcome may be inefficient (and inconsistent with the pricing principles)

(b) incentives for distributors to ensure connection costs are efficient. If connection costs are fully recovered through capital contributions, then they become akin to a pass-through cost for distributors with little or no direct financial incentive to ensure costs are contained, or that cost vs. quality trade-offs are explored

(c) incentives for access seekers to ensure costs are efficient. If access seekers pay standardised or very low connection charges then they may have weak incentives to ensure they factor distribution costs into their siting, reticulation, or sizing decisions

(d) transaction costs for access seekers and distributors. If capital contribution policies are not clear, provide overly wide discretion or involve overly complex calculations, then

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[68] This discussion on connection pricing is in relation to load customers and not generation or distributed generation connection customers.

[69] Climate Change Commission, 2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan, April 2023: p.120, see: https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/advice-for-preparation-of-emissions-reduction-plans/2023

[70] Some industrial customers electrifying their process heating can optimise their costs if a distributor can provide them with non-firm access to capacity. The same can be true for irrigation loads and could be true for some transportation loads.

costs may be unpredictable for access seekers and processing costs may be disproportionate for distributors

(e) incentives for distributors to optimise growth costs. If distributors are heavily reliant on capital contributions to fund system growth investment this can encourage a reactive and incremental approach that may be less efficient than a more strategic or well-optimised approach to investment

(f) coordination incentives. If access seekers are allocated a large share of any upgrade costs triggered by their connection, then this can disadvantage one access seeker relative to earlier or later access seekers (or existing users whose demand has grown over time, or who would otherwise have paid for renewal of the upgraded asset at some point in the future). This problem arises because capacity is added in discrete increments, and because it can be efficient to build anticipatory capacity.[71]

7.9. Appendix D looks at how the Authority recently dealt with connection pricing for transmission – to add context to the discussion on the issues for distribution networks.

7.10. The Authority and the Commerce Commission have both recognised the need to increase regulatory focus on connection pricing. In its recent open letter to distributors,[72] the Authority encouraged distributors to consider any significant first mover disadvantage (FMD) issues facing customers seeking to connect to their networks. The Commerce Commission recently expanded reporting requirements relating to customer connections,[73] and electrification is a key focus of the current input methodologies review and key consideration for the next set of price path determinations.[74] Appendix B discusses the interrelationship between connection pricing and the Price-Quality Regulation regime for Distributors.

7.11. The Government has also become involved in matters relating to connection charges. The Low Emission Transport Fund (LETF) [75] has had a significant focus on supporting the establishment of Public EV charging infrastructure. The Government Investment in Decarbonising Industry Fund (GIDI)[76] provides funding for industrial processes to switch to cleaner energy options. Both funds are administered by EECA.

7.12. The Minister of Energy has set out her expectations in this area in the annual Letter of Expectations to the Authority:[77]

> *Maintain focus on the regulatory settings for the distribution sector, including how connection costs and pricing for public electric vehicle (EV) chargers can facilitate the electrification of transport, and how access to metering information can better support demand flexibility. In particular, within the next four months investigate and develop actions to address variation and EV connection charges for public EV chargers across the country, as well as other regulatory barriers to the roll-out and adoption of EV technology.*

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[71] The need to build anticipatory capacity can lead to first mover disadvantage (which is a subset of these coordination issues). The first mover disadvantage issue has been recognised in the past by the Authority and other agencies including the Climate Change Commission (see paragraph 7.6 and footnote 73 above).

[72] Electricity Authority, Open letter to distributors, 19 September 2022

[73] Targeted-Information-Disclosure-Review-for-Electricity-Distribution-Businesses-Tranche-1-final-decisions-reasons-paper-25-November-2022.pdf (comcom.govt.nz)

[74] Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Proposed-process-25-May-2023.pdf (comcom.govt.nz)

[75] https://www.eeca.govt.nz/co-funding/transport-emission-reduction/low-emission-transport-fund/

[76] https://www.eeca.govt.nz/co-funding/industry-decarbonisation/gidi-contestable-co-funding/

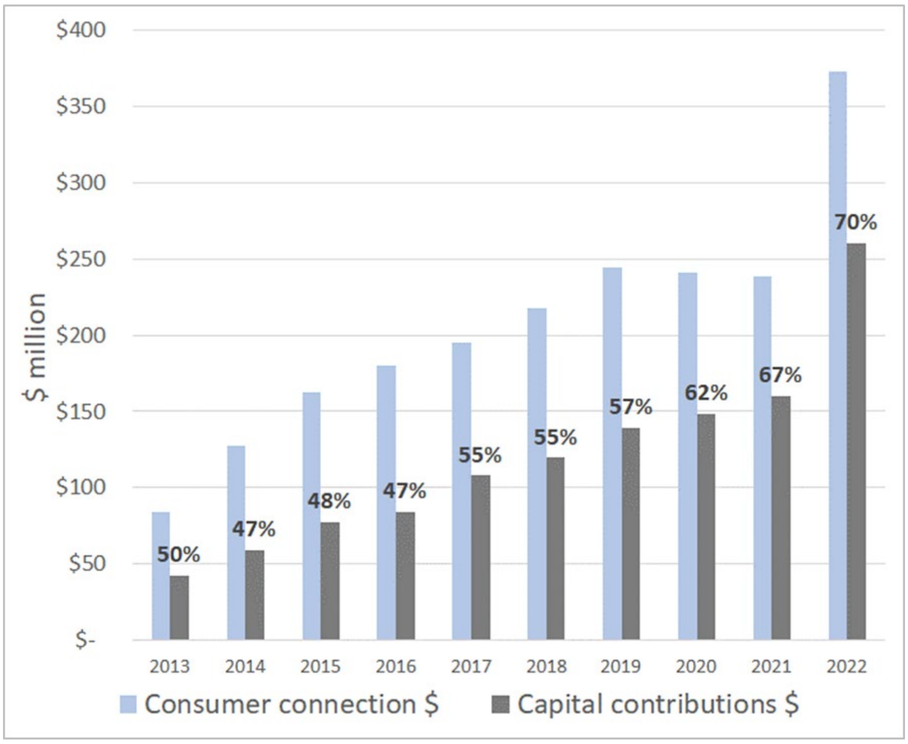
[77] Letter_of_expectations_2023_24.pdf (ea.govt.nz) https://www.ea.govt.nz/documents/2686/Letter_of_expectations_2023_24.pdf

7.13. This paper specifically addresses connection costs and pricing for load customers on distribution networks, which can include public electric vehicle (EV) chargers.

Current Situation

7.14. Figure 5. includes the annual total of capital expenditure by distributors on consumer connections,[78] and the amount funded through capital contributions. The percentage of consumer connection expenditure funded by capital contributions is overlaid on the graph and this has increased steadily since 2019.

Figure 5: Connection investment is growing, with a growing share funded through capital contributions



Source: Commerce Commission - Summary of Information Disclosure Information

7.15. There is a wide variation in connection pricing practices across the sector, including in matters such as:

(a) whether access seekers contribute to the cost of upgrading shared assets, and if so:

(i) how 'deep' they contribute. For example, a 'shallow-ish' contribution policy may require contributions only to assets at the same voltage as the connection whereas a 'deep' policy may require contributions to upstream assets at higher voltages

(ii) what share of the in-scope costs they contribute - including whether contributions cover any anticipatory capacity built to accommodate future growth

[78] Electricity Distribution Information Disclosure (Non-material) Amendment Determination 2023 27 April 2023 (comcom.govt.nz): **consumer connection** in relation to expenditure means expenditure on assets where the primary driver is the establishment of a new customer connection point or alterations to an existing customer connection point. This expenditure category includes expenditure on assets relating to- (a) connection assets and/or parts of the network for which the expenditure is recoverable in total, or in part, by a contribution from the customer requesting the new or altered connection point; and (b) both electricity injection and offtake points of connection

(iii) whether contributions are adjusted (by way of a refund) if another access seeker later connects to the same assets

(b) whether access seekers contribute to overall system growth instead of (or in addition to) contributing to specific upgrades triggered by their connection

(c) how much discretion the distributor reserves - for example, regarding whether deeper contributions will be required

(d) whether formula-based approaches are used, and the rationale for any formulae

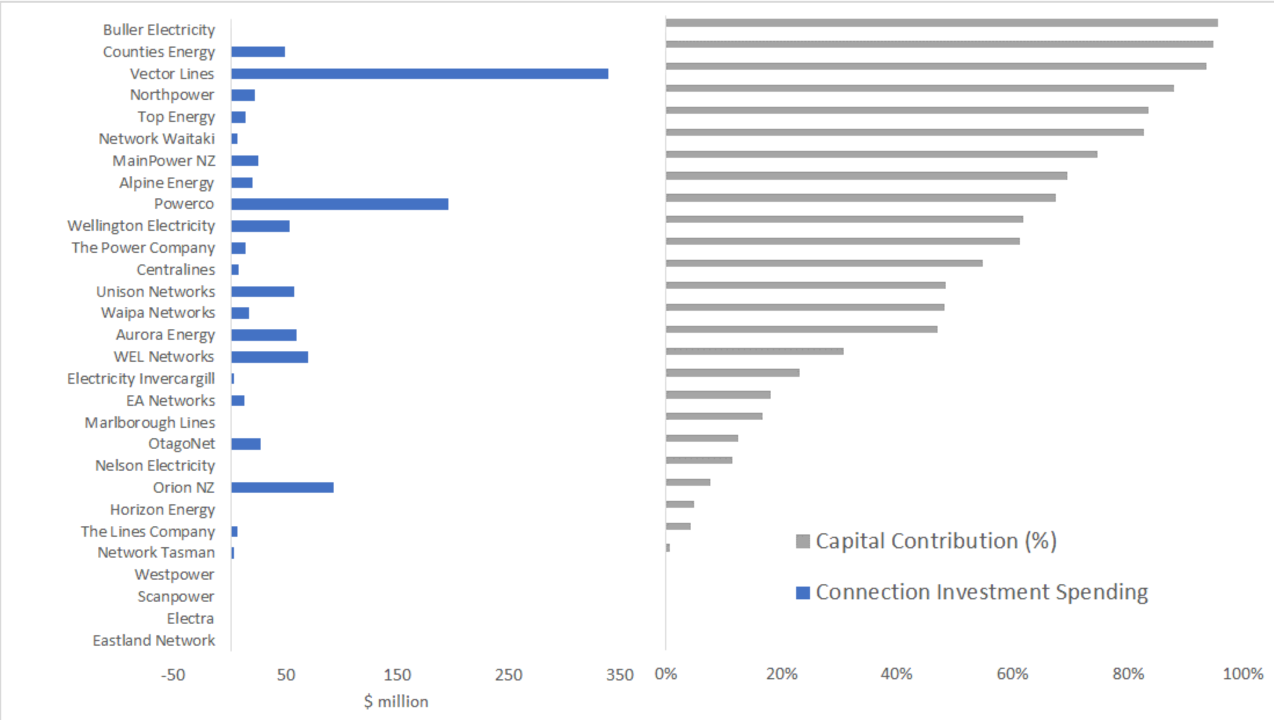
(e) whether standard or capped contribution amounts are set for some types of connection

(f) whether access seekers can contract for works directly.

7.16. Six of the 28 distribution pricing policies we have examined require new customers to contribute to the cost of upgrading capacity beyond their immediate connection. Such a charge has different names, including connection levy, infill housing fee, network development levy and growth fund.

7.17. As shown in Figure 6, this variation in practices produces a wide variation between networks in the share of costs allocated to access seekers. The lack of standardisation between networks can also raise transaction costs for access seekers, while producing widely differing up-front costs that can be difficult to predict and factor into plans.

Figure 6 - There is wide variation between distributors in their reliance on capital contributions



Source: Commerce Commission - Summary of Information Disclosure Information for 2019 to 2022

Q19. Do you agree with the assessment of the current situation and context for connection pricing? What if any other significant factors should the Authority be considering?

Problem statement

7.18. Connection pricing is becoming more important as electrification drives a step change in activity from access seekers. There is evidence of a wide variation in practices, a lack of standardisation, a lack of transparency, and adoption by some distributors of inefficient pricing approaches. These factors contribute to a range of problems (that vary by network):

(a) high transaction costs, which can deter or frustrate new demand. This can arise due to unclear or complex connection pricing policies, and due to the lack of consistency between networks

(b) overly high-cost allocation that may deter efficient demand expansion, including decarbonisation investments. This could arise if costs allocated to access seekers are relatively high within the subsidy-free range

(c) weak (or no) incentive on distributors to ensure connection costs (as opposed to charges) are efficient. This can arise if connection funding is primarily through capital contributions, which makes connection costs akin to a pass-through cost

(d) weak (or no) incentive on distributors to ensure system growth costs are efficient. This can arise if distributors rely too much on connection activity to fund system growth investments

(e) weak (or no) incentive on access seekers to ensure costs are efficient. This can arise if access seekers pay very low or fully standardised charges

(f) weak incentives for parties to coordinate connection and associated system growth investment. This can arise through a combination of the above factors.

Q20. Do you agree with the problem statement for connection pricing?

Preferred pricing

7.19. The Authority's preferences for connection pricing are less definitive than for some of the other areas covered in this paper. The Authority would prefer:

(a) a balanced approach that incentivises both access seekers and distributors to optimise costs, with a preference towards reducing allocations to access seekers where these are overly high (noting that such allocations should be subsidy free)

(b) more standardisation of connection pricing and greater transparency, such that charges are more predictable and the allocation of costs between access seekers and existing customers is clearer, and

(c) flexibility for access seekers to balance cost vs. quality where relevant.

7.20. If access seekers contribute too little to the cost of new connections, then:

(a) they may pay less than avoidable cost, such that existing customers subsidise their service. It is not necessary for contributions to cover 100% of dedicated asset costs to avoid this outcome, because use-of-system charges cover all asset renewal and maintenance costs. This means an access seeker could pay less than 100% of their asset costs up-front, but still pay more than their avoidable costs over time (hence benefiting all network users). Developing a clear view of the subsidy-free range by consumer group can help a distributor determine how low they can set contributions without long-term disadvantage for existing customers

(b) their incentive to optimise costs - for example, through their siting, routing, or capacity choices - may be too weak

(c) distributors may carry excessive prudential risk should the access seeker fail to connect or cease operation and leave stranded assets (that cannot be redeployed).

7.21. If access seekers contribute too much to the cost of new connections, then:

(a) they may be incentivised to under-size their connection or deterred from connecting at all. This may be due to the high cost of connection, or the unpredictability. Either way, this is a poor outcome for existing users if the access seeker would otherwise have at least covered their avoidable costs (and would have brought benefits such as decarbonisation, housing supply or economic activity)

(b) they may subsidise existing users. For example, if access seekers pay a large share of system growth costs, or of shared asset upgrade costs triggered by their connection, then they will be paying for investment that also brings benefits in terms of accommodating organic (per connection) growth, renewing or modernising ageing assets, and (typically) providing capacity for later access seekers

(c) distributors may have little or no incentive to ensure connection costs are efficient, because capital contributions are akin to a pass-through cost for non-exempt distributors

(d) distributors may also find it difficult to optimise their system growth investment if they are overly reliant on contributions for funding. Contributions-based growth funding favours more ad hoc or incremental investment approach that may be especially inefficient at a time when rapid growth is anticipated.

7.22. Some stakeholders have argued that it is less harmful to err on the side of lower (but not zero) contributions - ie, the downsides of contributions being too low are not as bad as the downsides of contributions being too high. The logic is that:

(a) provided access seekers meet their avoidable costs, existing users are not made worse off and electricity consumers are better off (because they now include the new or expanded usage)

(b) if access seekers pay more than their avoidable costs then the risk of them not connecting (or upgrading) should be weighed against the risk of reducing demand from existing users (compared to a situation where the access seeker contributes to shared costs)

(c) if the use of system charges are subsidy-free, they will contribute to renewal and growth expenditure across the network – including renewal of connection assets. As such, recovering 100% of the cost of dedicated assets through capital contributions (with no contribution to deeper upgrades or general growth) can potentially result in access seekers paying more than avoidable cost (over the lifetime of their connection)

(d) as such, distributors should be cautious when setting high contributions (including growth contributions) unless they have a clear understanding of subsidy-free ranges.

7.23. Conversely, some parties have indicated that there are situations where higher capital contribution charges may be preferable, provided this reduces ongoing distribution charges. This position may be most relevant to large users who are not part of a large consumer group – ie, where it may be the case that there is a direct trade-off between paying upfront vs. paying annual charges.

7.24. The Authority is interested in stakeholders' views on this balance.

7.25. With increasing volumes of connection requests, there is increasing value in offering more standardised pricing options for volumetric-style access seekers – for example, with fully fixed charges or with standardised rates based on length and connection capacity (potentially with a standard surcharge for congested locations). This simplifies pricing for the distributor, makes charges more predictable for the access seeker, and streamlines access overall. At the other end of the spectrum, there is value in distributors allowing customer-focussed cost vs. quality trade-offs for customer who could feasibly implement non-firm access arrangements.

7.26. The Authority's current view is that it does not support using capital contributions to fund anticipatory capacity unless a distributor has a robust view of the subsidy-free range for each of its consumer groups and can be confident that anticipatory capacity charges will not impose a disproportionate burden. Charging for anticipatory capacity through capital contributions makes pricing less predictable and, without active management of residual cost allocation, more likely to be inefficiently high.[79]

7.27. The Authority would like to see greater consistency between distributors in their terminology, processes, and approaches. This is of value to access seekers (and the parties who assist access seekers) who operate across networks.

Q21. Do you agree with the Authority's preferred pricing approach for connection charges?

7.28. Complementary measures that would assist access seekers include:

(a) providing information on asset locations (for example, through open GIS) and network capacity (for example, by publishing heat maps). Providing access seekers with information helps them to plan their investments and to target areas where they can expect lower costs and less delay. As application volumes increase, including from access seekers with greater design and locational flexibility, it becomes inefficient to supply location and capacity information via the application process

(b) allowing access seekers to contract works directly from a large pool of approved providers. This is valuable because market sourcing disciplines the cost of connections, and especially important where distributors have high capital contributions and hence limited incentive to ensure costs are efficient.[80] However, the benefits must be weighed against any additional costs it may impose, especially in regional areas where there may be may not sufficient contractors to create a pool of service providers.

7.29. Both the complementary measures mentioned above are of interest to the Commerce Commission and the Authority. The Authority is considering these matters further as part of its work on regulatory settings for distribution networks.

Q22. Do you have any thoughts on the complementary measures mentioned above and to what extent work on these issues could lead to more efficient outcomes for access seekers?

Options

7.30. The options the Authority is considering are:

(a) do nothing. The incentive for non-exempt distributors to use capital contributions to manage forecasting risk and mitigate financeability challenges[81] could potentially be

[79] This position is consistent with transmission, where anticipatory capacity costs can be funded through transmission charges rather than transmission agreements (which are equivalent to capital contributions).
[80] Distributors could be incentivised to allow service providers to subsidise work on existing assets through higher charges for access seekers.
[81] NERA Economic Consulting, *Financeability considerations under the DPP* 16 January 2023 Appendix-D-of ENA Submission on IM Review CEPA-report-on-cost-of-capital (comcom.govt.nz) https://comcom.govt.nz/__data/assets/pdf_file/0021/308505/ENA-Appendix-D-NERA-report-Financeability-Submission-on-IM-Review-CEPA-report-on-cost-of-capital-16-January-2023.pdf

mitigated through changes to the Commerce Commission's regulatory settings and distributors could voluntarily coordinate improvements, towards consistency

(b) extend practice note and scorecards to address connection pricing methodologies. We could weight 2024 scorecards toward connection pricing, and update the practice note to cover matters such as terminology, design considerations, and preferred approaches

(c) prohibit or mandate specific approaches. For example, we could:

  (i) prohibit pricing methodologies that allow overly deep contributions, contributions to anticipatory capacity and overly high contributions to general system growth

  (ii) set caps on fees, or on cumulative fees (where an access seeker has to apply multiple times to find a suitable site)

  (iii) mandate particular approaches for some connection types or classes of access seeker. For example, we could require standardised charges or standardised cost building blocks for public EV chargers and housing

  (iv) mandate implementation of the Authority's guidelines on transmission pass-through

(d) call in connection pricing policies for review and approval, either for specific distributors or across the board. For example, we could call in:

  (i) methodologies of high-risk distributors who have heavy reliance on contributions and high activity levels, or high levels of access seeker dissatisfaction

  (ii) treatment of cumulative fees for repeat applications

  (iii) pass-through of transmission charges.

Q23. Are there other options you think the Authority should consider for connection pricing?

Analysis of options

7.31. Doing nothing is not our preferred option, because the Authority's regulatory toolset should complement the Commerce Commission's and there is clear scope to improve connection pricing practices to enhance efficiency.

7.32. Extending practice notes and scorecards to address connection pricing is unlikely to be sufficient but would complement other measures. Reasons for thinking this will not be sufficient are:

(a) facilitative and reputational measures have not produced rapid or universal improvements in the case of use of system pricing

(b) distributors may prefer their status quo, including because change can be costly and disruptive and because they have incentives to rely on contributions to an inefficient extent - including to mitigate forecasting, financing, and cost recovery risks.

7.33. We expect distributors may be more responsive to these measures if we introduce backstop provisions for prohibiting or mandating pricing approaches, and/or a framework for calling methodologies in for review and approval. However, this may not be enough to overcome the second point above.

7.34. Prohibiting or mandating specific approaches may be an effective way to achieve a rapid initial improvement in the overall efficiency of connection pricing - or at least to prevent approaches that are clearly inefficient for any distributor. A potential implication is that this could engage statutory provisions that allow the Commerce Commission to reopen allowances. This could help ensure distributors are not left under-funded during their next control period due to an un-forecasted reduction in contributions (and hence an increase in net connection costs).[82]

7.35. A call-in regime would likely improve the efficacy of practice notes and score cards, while providing a mechanism for faster progress on important issues or for priority distributors. Call-in is well suited to aspects of pricing for which a common approach across all distributors is unlikely to be efficient, or where innovation by distributors is more valuable than consistency across distributors.

7.36. Overall, the Authority sees value from the full suite of intervention options.

7.37. Provided over page is a summary of the issues associated with EV charger connections and options for addressing these.

Q24. Which if any of the above options do you consider would best support distribution pricing reform in the area of connection pricing?

[82] In 2024 the Commerce Commission will determine distribution revenue paths for the four to five years from April 2025. The Commission is planning to consider the distributor forecasts disclosed in August 2023, with some capacity to adjust for updated forecasts disclosed August 2024 (ID date for year ending 31 March 2024). ComCom *Default price-quality paths for electricity distribution businesses from 1 April 2025* 25 May 2023 See: Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Proposed-process-25-May-2023.pdf (comcom.govt.nz)

Electric Vehicle Charger Issues and Options

Electrification of transport is a key component of the energy transition. EV uptake is expected to increase substantially in the near term. (Figure 8 in Appendix C). An increase in charging facilities will be required to support this change.
Charging will occur at private premises and public facilities. A variety of charging infrastructure will be used including 3-pin plug-in chargers, fast at home chargers and large scale public charging sites.

Different types of charging infrastructure will be required to:

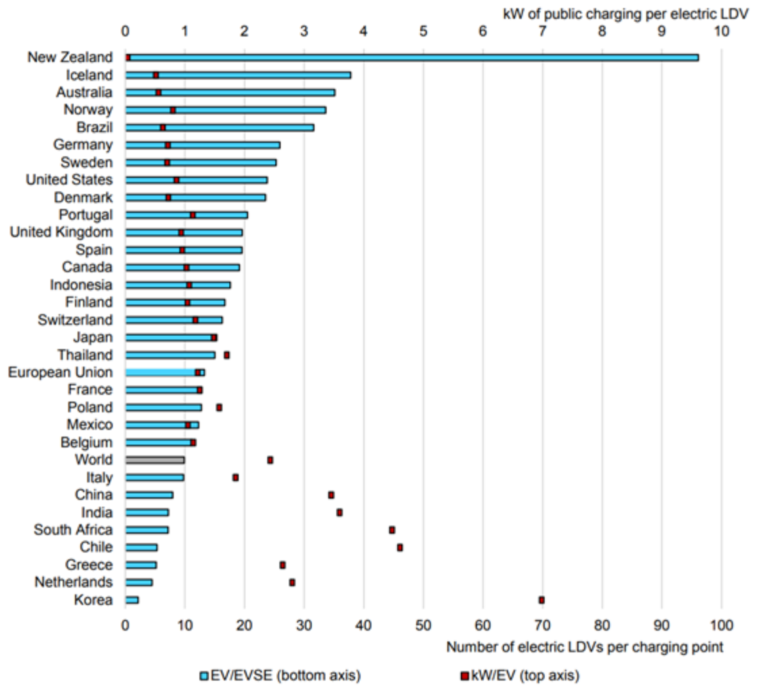
- support urban use in a variety of settings
- support long-distance inter-metro travel
- enable electrification of different types of vehicles.

New Zealand has one public EV charger for every 95 EVs. This is low compared to most other countries.

The inference is that New Zealand is lagging other countries in installing public EV charging infrastructure.

Source International Energy Agency *Global EV Outlook 2023 Catching up with climate ambitions. Pg. 48* [EV1]

Figure 1.16 Number of electric light-duty vehicles per public charging point and kW per electric light-duty vehicle, 2022



IEA. CC BY 4.0.

Stakeholders have raised concerns that connection charges and processes are slowing the roll-out of public EV chargers. Some distributors are concerned about the impacts that EV chargers could have on networks. Our statutory objective includes promoting competition and the efficient operation of the electricity industry for the long-term benefit of consumers. We are responsible for distribution pricing which includes pricing for connections such as those required by access seekers wanting to establish EV charging facilities.
This issues paper discusses the price-related matters that are within the Authority's scope.

Issues raised

- The variance in connecting methodologies and approaches creating complexity
- The % of connection costs charged as capital contribution are set by the EDB and are non-negotiable
- Connection costs can include charges for wider network growth and first mover disadvantage
- Ongoing tariffs for EV chargers are unpredictable

- Few options for network connection work
- Long lead times for new connections

- Connection costs are seen as being too high

EV1. https://iea.blob.core.windows.net/assets/dacf14d2-eabc-498a-8263-9f97fd5dc327/GEVO2023.pdf

Possible solutions

- Expand scorecards to include connection charges
- Prohibit or limit inefficient approaches for capital contributions in the Code.
- Mandate specific approaches
- Targeted call in of a particular EDB for review of connection charges (capital contributions)
- Establish public EV charger customer class

- Non-price access terms could be considered by Electricity Authority

- Scrutinizing the actual cost incurred by an EDB to create a connection (materials, civils, traffic management), is outside of Electricity Authority's scope

8. Retailer response

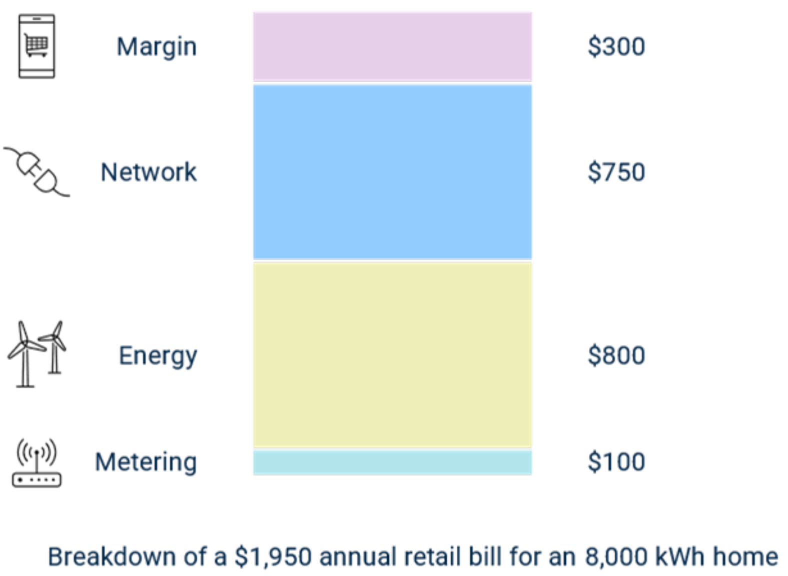
8.1. This section of the paper considers the role of retailers. Most end users pay for network costs via a retail tariff, rather than transacting directly with distributors. This means retailers are the direct consumers of distribution tariffs, so their response to distribution price signals is important. One way for retailers to respond is to pass distribution pricing features (such as lower off-peak rates) through to retail pricing. Some distributors cite lack of retail pass-through as a reason to delay reforming their own pricing.[83]

Context

8.2. Some large end users purchase energy, network, and metering services directly, but most end users buy a retail service that bundles all necessary inputs together. This means retailers are the direct consumers of distribution tariffs, so their response to price signals is important.

8.3. For a typical end user, energy and network services are similarly material inputs to the retail service - noting that distribution tariffs include a transmission pass-through component.

Figure 7 Input costs and Margins for a $1950 retail bill for an 8,000kWh home



Notes on estimates: Input costs and margin based on averages across retailers as reported by the Authority[84]

8.4. Energy costs are highly dynamic - nodal prices vary through the day to signal the marginal cost of generation and transmission. Energy prices are typically highest during peak demand periods, meaning there is good correlation between network peaks and energy price peaks.[85]

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83 Network-Waitaki-DP-Practice-Note-submission-2021.pdf (ea.govt.nz) p6. see https://www.ea.govt.nz/documents/1564/Network-Waitaki-DP-Practice-Note-submission-2021.pdf

84 https://www.ea.govt.nz/news/general-news/new-zealands-electricity-retail-market-retail-gross-margins/

85 There are exceptions at a more local level (eg, where load on a portion of a network has a different profile from the national average) and this correlation is expected to reduce in coming decades as renewable generation increases.

8.5. Distribution charges have traditionally had uniform usage charges for most consumers, with no variation through the day. With this mix of input costs, retail tariffs have traditionally also had a simple two-part structure with a fixed ($ per day) charge and a uniform usage ($ per kWh) charge - ie, retailers have passed through the network pricing structure rather than the energy pricing structure.[86] This structure is familiar to New Zealand consumers and is how most people expect to pay for electricity.

8.6. Billing on accumulated monthly demand was also the only mainstream option for volume-based charging prior to the widespread availability of smart meters. Legacy meters typically recorded only accumulated energy consumption and were read monthly or two-monthly. Smart meters record half-hourly consumption and many can be read remotely. Mass rollout of smart meters started from 2006, with Arc Innovation's deployment in Christchurch.

8.7. As distributors begin to offer more cost-reflective non-uniform tariffs, retailers potentially face a change to their input costs and have choices for how they respond. How much this potential change becomes reality depends on:

(a) tariff assignment - distributors can make non-uniform tariffs available on an opt-in or opt-out basis, or make them compulsory

(b) profiling approach - there are three ways that daily (or monthly) consumption data may be fitted to a through-day (or peak vs. off-peak) profile:

(i) actual profile - half-hourly consumption data from smart meters is used to determine profiles and breakdowns. If a user shifts the timing of their consumption, then this will directly impact their retailer's input costs

(ii) deemed profile - daily or monthly consumption data is fitted to a pre-determined through-day profile. If a user shifts the timing of their consumption, then this will not alter the retailer's input costs

(iii) residual profile - daily or monthly consumption data is fitted to the residual profile at the grid exit point (ie, actual GXP profile less any actual or deemed ICP consumption). If a user shifts the timing of their consumption, then this will alter input costs for all retailers not using actual data or deemed profiles. In other words, the impact on their own retailer's input costs is muted.

8.8. Assuming a retailer is exposed to a non-uniform distribution price signal (ie, the ICP is assigned to a non-uniform tariff and billed on actual data) there are broadly three ways they may respond:

(a) information - encourage users to shift their consumption to off-peak periods. This can be general information (eg, an information campaign) or more targeted information (eg, an alert on a cold evening)

(b) control - directly influence their customers' demand. For example, by procuring or managing embedded flexibility resources

(c) pricing - adopt a cost-reflective retail price structure. For example, adopting non-uniform usage charges or providing a rebate to reward favourable consumption profiles.

8.9. Retailers have a commercial incentive to manage their input costs to:

(a) reduce risk - for example, if a retailer repackages a time-varying distribution charge into a uniform retail charge then their margin is impacted by any changes in the actual profile of their customers' consumption. The materiality of this risk depends on the

[86] Retailers have also traditionally passed through discounts for controlled hot water, which is another common structural feature of traditional distribution pricing.

predictability of consumer demand, and the strength of any price signals. For example, if there is a small difference between peak and off-peak rates then the risk is small

(b) remain competitive - provided there is consumer appetite to take up more cost-reflective retail offers, retailers that continue to offer only uniform options will (over time) attract a peakier customer base that costs more to serve. They will also have to price in the risk described above. These dynamics either compress margins or make prices less competitive. Appendix F illustrates this dynamic.

Current situation

8.10. Many distributors have now developed non-uniform tariffs, though several factors mute the impact of these early steps:

(a) distributors typically start with 'mild' differentials between peak and off-peak rates. This may be prudent for managing customer impact, but means the peak signal is relatively muted initially

(b) many retailers are billed on deemed or residual profiles, even where properties have smart meters installed. This significantly reduces incentives to manage input costs because any savings are shared with competing retailers

(c) distributors typically offer non-uniform tariffs on an opt-in basis initially, or with permissive opt-out. As such, retail uptake likely remains relatively low

8.11. Other factors that introduce a lag into the process of transitioning away from uniform retail tariffs include:

(a) consumers are familiar with traditional tariff structures. While early adopters may seek out options with lower off-peak rates, mainstream adoption will take time and require marketing and product development effort

(b) large, established retailers often have billing systems that are relatively inflexible and costly to change

(c) most retailers operate nationwide, so will tend to have a national perspective on when and how to develop, market and support new products - eg, retailers may prefer to use consistent off-peak periods nationwide in their produces

(d) LFC regulations are partway through their phase-out path. Until retailers are able merge low and standard residential users into a single product, the LFC requirements add complexity and constraints to retail pricing design.[87]

8.12. Notwithstanding the factors discussed above, there is good retail availability of non-uniform tariffs. Based on desktop research of retail offers from 11 retailers with a market share of more than 80% of ICPs, we found:[88]

(a) nine retailers have nationally available non-uniform options alongside their traditional uniform tariffs, two have 'free power' offers and one only offers uniform charges

(b) most of the non-uniform offerings use consistent time periods nationwide, though sometimes with exceptions. For example, many retailers adopt bespoke time periods for the Orion network

(c) three of the nine retailers with nationally available non-uniform plans restrict eligibility to customers with EVs. Some of these three do offer non-uniform plans to all users in specific network areas.

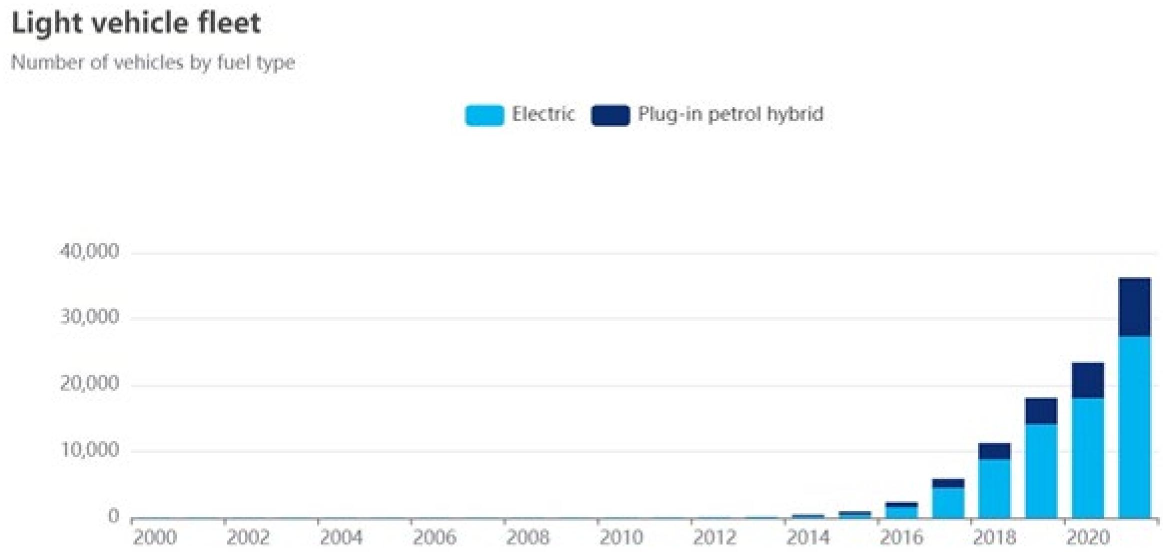
8.13. This snapshot of current offers indicates that retailers have made progress with product development and marketing. The targeting of EV owners is consistent with EV owners

[87] The regulations will be removed from April 2017. Some retailers may choose to merge low and standard products ahead of that date (ie, by using the maximum LFC rate for all residential customers).
[88] We did not include Trustpower, because Mercury have indicated they will discontinue this brand.

being early adopters, with flexible demand, and high usage - ie, likely to take up and benefit from non-uniform pricing options. Retailers may also view EV owners as desirable customers, and it is natural to expect someone purchasing an EV would be attracted to retailers who can provide low-cost off-peak charging.

8.14. Figure 8 shows that the number of EVs in the New Zealand light vehicle fleet is growing rapidly. However, in 2021 electric and plug-in hybrid vehicles made up less than 1% of New Zealand's light vehicle fleet. This suggests there is significant potential for the consumer trend of growing EV uptake to have a growing impact on electricity retailer pricing behaviour in coming years.

Figure 8: The number of EVs is growing rapidly



Source: Ministry of Transport open data tool. 2021 fleet statistics. Fleet statistics | Ministry of Transport

8.15. The apparent preference amongst retailers for nationally consistent off-peak periods may reflect that this is the current 'sweet spot' between the benefits of cost-reflectivity versus the benefits of simpler consumer offerings. This may change as the market evolves, and as price signals strengthen.

8.16. We are aware that some retailers are accessing flexibility services.[89] However this practice does not yet appear to be widespread and may not be at a scale sufficient to manage retailers' network input costs. Key factors that may still be influencing this include:

(a) use of deemed and residual profiles for energy and network purchases. This mutes any incentive to shift the timing of demand as a way of managing input costs because the retailer will not be billed on the actual (shifted) demand

(b) the most valuable flexibility service (in terms of available response) is hot water ripple control. This is a broadcast technology that cannot generally be used to target an individual retailer's customer base.[90] As such, even assuming all retailers were billed on actual data, a retailer paying for ripple control to manage their input costs would also lower their competitors' costs. This weakens the incentive for any individual retailer to contract for access to ripple

[89] The Authority is also aware that some distributors are concerned about potential congestion issues arising from non-EDB-controlled DER responding to price signals.
[90] In some limited circumstances an individual retailer can manage their customers on a network utilizing ripple control.

(c) we are not aware of distributors having well developed contracting frameworks for allowing widespread retailer access to ripple control. However, this is not surprising given the factors above would mute any retailer demand.

8.17. There are more than 2 million half-hour certified meters in New Zealand, which means just under 90% of ICPs have no physical metering impediment to billing on actual data.[91]

Q25A. Do you agree with the assessment of the current situation and context for retailer response? What if any other significant factors should the Authority be considering?

Q25B. [***for retailers***]: What plans do you have for responding to distribution price signals as distributors reform their price structures? What barriers do you see to responding efficiently?

Q25C. [***for distributors***]: What plans do you have to increase the proportion of your customers that face time-varying charges (for example, making TOU plans mandatory for retailers whose end-users have an AMI meter installed)?

Problem statement

8.18. Concerns about lack of retailer response to distribution pricing signals is deterring some distributors from progressing pricing reform.[92] While we can observe some response from retailers, including off-peak pricing offers, there are two factors that appear to weaken retailer incentives and so significantly contribute to a lack of efficient retailer response to distribution prices:

(a) continued use of deemed or residual profiles for energy and network billing for ICPs with advanced meters

(b) overly permissive assignment policies for transitioning ICPs to non-uniform distribution tariffs.

8.19. Our current view is that the Authority should address these two issues first, before looking further at other issues around retailers' response to distribution prices.

Q26. Do you agree with the problem statement for retailer response?

Preferred pricing

8.20. The Authority's current view is that it would prefer to see:

(a) retailers billed on actual half hourly usage for energy and network costs for all ICPs with capable meters, which includes almost 90% of ICPs

(b) distributors providing very limited (or zero) grounds for opting out from non-uniform tariff options.

Q27A. Do you have any comments on the Authority's preferred pricing?

Q27B. [***for retailers***]: What use do you make of deemed and residual profiles? Please explain the reasons for this. What barriers do you see to phasing out use of deemed and residual profiles?

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[91] April 2023 data from EMI. ICP count is 2.27 million, of which 2.02 million have meter type AMI (HHR certified). www.emi.ea.govt.nz/r/43dx5

[92] Vector submitted that the Authority should … "ensure distribution pricing signals are passed through in some form in retail prices. … There appears to be little return from developing more sophisticated price signals that are not passed through and are therefore not seen by consumers, for whom pricing is intended to benefit." Vector-DP-Practice-Note-submission-2021.pdf (ea.govt.nz) https://www.ea.govt.nz/documents/1574/Vector-DP-Practice-Note-submission-2021.pdf. Similarly, Northpower submitted the Authority should "ensure there is some form of pass-through of price signals, as it is hard to rationalize further price reform when existing price reform has had no effect due to no pass through." Northpower-DP-Practice-Note-submission-2021.pdf (ea.govt.nz) see https://www.ea.govt.nz/documents/1566/Northpower-DP-Practice-Note-submission-2021.pdf, p.16

Options

8.21. Options the Authority is considering are:

(a) do nothing. Market dynamics create some pressure on retailers to improve their performance - most notably the growing share of consumers with EVs who tend to seek out low-cost off-peak rates

(b) extend practice note and scorecards. The practice note could provide more guidance on tariff assignment, and options for incentivising or requiring billing on actual data. Future scorecard rounds could examine progress in these areas

(c) support transition to billing on actual data. We could investigate options for phasing out access to deemed and residual profiles for energy purchases for ICPs with half-hour certified meters

(d) control or call-in distribution pricing. We could mandate or call-in aspects of distribution pricing to ensure progress on availability and uptake of non-uniform tariffs and appliance tariffs

(e) monitor retail pricing. We could increase our monitoring of retail pricing practices, including availability and uptake of non-uniform pricing options and appliance tariffs

(f) control or call-in retail pricing. We could prohibit or mandate certain retail pricing options or call-in high-risk retailers or aspects of pricing for review and approval.

Q28. Are there other options you think the Authority should consider for retailer response?

Analysis of options

8.22. Do nothing is not our preferred option, because we have options to sharpen incentives on retailers to manage their input costs and to address distributor reticence.

8.23. The Authority's preferred option is to:

(a) support transition to billing on actual data for network and energy purchases

(b) develop guidance on tariff assignment, with distribution pricing control and call-in as backstops

(c) monitor retail pricing.

8.24. Billing on deemed or residual profiles severely weakens incentives for retailers to manage their energy and network input costs by shifting demand (whether directly, or through price signals and information). With penetration of capable meters approaching 90%, metering is not a major impediment. We will investigate options to speed the transition to billing on actual data, recognising this may require investment by some retailers to enhance their information systems. This issue has previously been raised by two of the Authority's advisory groups.[93] In July 2021, the Authority's Innovation and Participation Advisory Group (IPAG) recommended 'setting a profiling sunset date at which half hour reconciliation becomes mandatory for all capable sites. This could also be achieved by setting a sinking cap on the percentage of a participant's half hour capable sites reconciled by profile.'

8.25. Many distributors retain an opt-in approach or opt-out with wide access to exemptions. These approaches can lead to adverse selection (where peakier customers remain on uniform tariffs) and weaken retailer incentives to grapple with non-uniform tariffs. Extending

[93] Advice on reducing barriers to customer access to multiple electricity services Innovation and Participation Advisory Group updated July 2021 Slide 31
https://www.ea.govt.nz/documents/524/IPAG_advice_on_access_to_input_services.pdf

the practice note to cover tariff assignment provides and opportunity to capture and encourage best practice.

8.26. Appliance tariffs are also relevant to retailer incentives - both upkeep of tariffs that provide discounts for ripple-controlled hot water and extension of appliance tariffs to other control technologies and appliances. We expect to see distributor innovation in broadening availability of appliance tariffs and progress at ensuring appliance tariffs are made cost-reflective (eg, by providing anytime access to off-peak rates).

8.27. Assignment may suit control as a backstop, while appliance tariffs may be more suited to call-in. This is because appliance tariffs must work alongside eligibility management (ie, setting and checking criteria for allowance access to the tariff) and service levels (ie, the control rights associated with access to the tariff). In contrast, a more one-size-fits-all approach to assignment could be feasible.

8.28. Increased monitoring of retail pricing could help build a better picture of retailer response and provide a means to increase pressure for reform. Examples of monitoring that could be useful include:

(a) availability of TOU usage tariffs

(b) uptake of TOU usage tariffs

(c) structures of peak and off-peak rates

(d) strength of peak signals

(e) level of off-peak rates

(f) merging of standard and low-user pricing

(g) availability of appliance tariffs

(h) uptake of appliance tariffs.

8.29. The Authority intends to further consider what retail pricing information it would be appropriate to collect, likely later in 2023.

8.30. Direct intervention in retail pricing would be a significant departure from the Authority's approach to date. This could cause a significant change in the retail operating environment, with high risk of unintended consequences - including the risk of adversely impacting on competitive pressures that drive innovation, efficiency, and customer focus. The Authority's current view is that retailers have a role to play in managing network input costs on behalf on their customers. Alternative approaches (other than mandating pass-through of distribution prices by retailers) were supported by a number of submitters in the consultation on the 2021 DPPN.[94] There appears to be evidence of early retail response to distribution pricing, which should accelerate with changes to strengthen retailer incentives to manage input costs, with strengthening distribution pricing signals, and with growing consumer familiarity with new pricing options.

Q29. Which if any of the above options do you consider would best support distribution pricing reform in the area of retailer response?

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[94] IPAG, Electric Kiwi & Unison all responded that the Authority should not mandate pass through. IPAG stated: 'Prices need to be observed by someone who has the capability to respond", https://www.ea.govt.nz/documents/1560/IPAG-DP-Practice-Note-submission-2021.pdf p2., Electric Kiwi: 'Mandating pass-through is an option wholly incompatible with operation of a competitive electricity market' https://www.ea.govt.nz/documents/1554/Electric-Kiwi-DP-Practice-Note-submission-2021.pdf p1. Unison we would not expect to see retailers pass-through network price signals 1:1 in retail prices' https://www.ea.govt.nz/documents/1573/Unison-and-Centralines-DP-Practice-Note-submission-2021.pdf, p4.

Appendix A Observations from assessment of 2023 distribution pricing material

A.1. This section looks at the progress distributors are making in reforming their distribution pricing structures to signal the economic cost of providing services. This analysis is based on our review of distributors' current pricing methodologies and tariffs and interviews we have had with the majority of distributors in the last six months.

Pricing structures for signalling peak demand

A.2. The Authority looked at the extent to which distributors are using tariff pricing structures to signal peak congestion periods. The majority (23/29) distributors now offer TOU tariffs to differentiate the cost of using their networks at varying times of day, or throughout certain periods of the year for residential customers. Most of these distributors also offer TOU tariffs to small/medium commercial customers.

A.3. A small number of distributors only offer TOU tariffs for residential consumers. These distributors have prioritised plans for residential consumers as they have identified that the load profile of residential consumers contributes to the network peak more than other consumer groups.

A.4. Other features of the residential TOU tariffs include:

(a) There was a mix of two-part structures - peak and off-peak periods, and three-part structures with peak, off-peak and shoulder time periods.

(b) Four distributors have tariffs that are referred to as TOU but appear to be legacy day/night tariffs.

(c) One EDB applies a 'peak charge' based on each retailer's share of usage at the time of the 200 – 300 peak half hours during the previous winter.

(d) In terms of intra-year variation, only one EDB incorporates a seasonality element in their TOU charges for residential consumers. This reflects the higher demand in winter months for networks other than those with a very significant irrigation load.

A.5. The impact of seasonal use has also been reflected in "winter demand" or "summer demand" tariffs. However, these charges appear to be based on individual customers' peak demand which does not necessarily coincide with the network peak demand.

A.6. Various reasons were provided by those distributors that do not offer TOU tariffs. The most common was the penetration of smart meters and the ability of retailers to deal with half hourly data. Other reasons stated were that distributors had spare network capacity and no congestion, (signals not required), they have delayed implementation of TOU to observe the outcome of other distributors and concerns around bill shock.

A.7. Eleven of the 23 distributors with TOU pricing have required this as "mandatory" if there is a smart meter installed and the retailer can submit verified half-hour data to the market. Some distributors are working with retailers to increase the customers on TOU tariffs while tightening criteria to ensure consistency across retailers.

A.8. Four distributors stated that TOU tariffs are optional. Some of this group indicated a preference to continue to allow the retailer to choose whether they applied TOU tariffs.

Ripple Control Tariffs

A.9. Ripple Control allows distributors to control hot water cylinders to reduce peak demand across their networks. 27 out of 29 distributors offer a discounted price for this load if subject to control.

A.10. Most distributors indicated that they would like some form of control over EV charging and that lack of visibility of private EV charging will be challenging. Some distributors also claimed ripple or other technology to control hot water cylinders and EVs would more efficiently manage network peaks than TOU tariffs.

Electric Vehicle Tariffs

A.11. Only three distributors offer a specific tariff for residential EV charging that signal the cost of charging EVs during peak and off-peak time periods.

(a) Wellington Electricity has a TOU price plan for EV and battery for both low and standard users.

(b) Electra offers TOU for EVs directed to standard users (>8,000 kWh annually). This tariff has lower charges for all the TOU bands. It currently has five customers enrolled.

(c) Mainpower has a customer price category for electric vehicles. There are no customers currently on this plan.

A.12. Several distributors indicated they are considering EV tariffs, primarily as a controllable load.

Connection Pricing

A.13. There is a wide variety of methods being used by distributors to price new or expanded connections and develop their capital contribution policies. Distributors commonly state their polices are based on incremental and avoidable cost principles and reflect the actual cost of the connection.

A.14. It is not unexpected that there are differences in approaches given the varied nature of New Zealand’s 29 distributors. We observed the following:

(a) some policies are imprecise and refer to network discretion to deal with new connections

(b) some policies only focus on specific types of customers eg, developers and subdivisions.

(c) Some policies do not provide detail about the variable / inputs used to calculate capital contributions

(d) the terminology across the policies is not consistent.

Customer types for calculating capital contributions

A.15. Just over half of the distributors use standard and non-standard customer types to determine their capital contributions. Typically, distributors offer a standardised connection price when there is a low degree of complexity and investment. For non-standard connection that requires more technical input and /or significant dedicated assets the EDB typically calculates the actual cost and applies a capital contribution on a case-by-case basis.

A.16. Other determine the approach based on capacity required. In Network Tasman the capital contribution depends on where the connection is located.

Existing assets on the wider network for calculating capital contributions

A.17. A large number of distributors include in their capital contributions a portion of existing electricity network assets associated with the wider network. Counties Energy refers to this as “upstream and downstream assets” in which customers pay for their direct connection assets and a contribution towards the existing upstream assets. The degree to which this is described and how it is described varies considerably between distributors.

Growth Fund or growth Levy

A.18. Six distributors' connection policies require new customers to contribute to the cost of upgrading the capacity of the wider network in the future. This is sometimes called a growth fund or a growth levy. Some distributors charge a standard price per kVA low voltage connections and a non-standard charge for high voltage connections. Others determine the levy depending on the capacity requirements.

Approaches to the First Mover Disadvantage

A.19. The First Mover Disadvantage and issues around anticipatory capacity were discussed in section 7 on Connection pricing. 12 of 29 pricing methodologies discuss charging for anticipatory capacity and describe their consistency with the Authority's pricing principles. There are two main approaches:

(a) Three distributors state that if they install network capacity greater than required by the connecting party, they may fund a portion of the additional cost.

(b) Nine distributors may charge for anticipatory capacity but may provide a rebate to the first connecting party should a subsequent customer connect and use some of the additional capacity installed. The rebates or refunds have specific conditions including timeframes.

Appendix B Connection prices and the Commerce Commission's regime under Part 4 of the Commerce Act

B.1. The Authority and the Commerce Commission both have regulatory powers and responsibilities for the electricity distribution sector. The Authority is responsible for pricing for transmission and distributions services refer to specific provision. The Commerce Commission's regulatory regime comprises Price-quality regulation (P-QR) and Information disclosure (IDs). 16 of 29 distributors are subject to P-QR. 13 are "exempt" based on criteria of community ownership and size. All distributors are subject to IDs.

B.2. Price-quality regulation includes:

(a) five-yearly revenue caps that aim to ensure distributors recover no more than their efficient investment and operating costs.

(b) efficiency incentives that encourage distributors to out-perform capital and operating expenditure allowances.

(c) network quality standards aimed at ensuring efficiency gains are not at the expense of compromised reliability.

B.3. Information Disclosures (ID) require every EDB to publish information each year detailing their performance.

B.4. There are aspects of the Commerce Commission's regulation that impact on the incentives on distributors. Those subject to "price-quality" regulation P-QR forecast capital expenditure for each five-year period including capex for customer connections (and for system growth and asset relocations). Where EDB's choose to recover expenditure on customer connections through a capital contribution, this amount is excluded from the regulatory capex and the regulatory asset base RAB. This is the same for exempt and non-exempt distributors.

B.5. There may be an opportunity for an EDB to use their capital contribution policies to manage risk around forecasting capital expenditure and maximise the outcome from incentives available in the P-QR regime.

B.6. Both operating expenditure and capital expenditure for non-exempt distributors are subject to Incremental Rolling Incentive Scheme (IRIS). This allows an EDB to retain a portion, 24%, of any underspend in forecast capital expenditure. This may incentivise an EDB to increase its cost recovery from capital contributions from access seeker rather than fund or contribute to the connection costs of access seekers.

B.7. The cost of customer connections met by access seekers is outside of the IRIS scheme, which weakens the incentive to ensure these costs are as efficient as possible. This means capital contributions are a pass-through cost for distributors.

B.8. Forecasting the volume and cost of customer connections may be challenging and more uncertain than distributors planned renewal work programme. This may incentivise an EDB to manage their risk by adjusting the capital contribution required.

B.9. The Commerce Commission is in the process of reviewing the IMs that will be used for the DPP reset from 1 April 2025. It is proposing to introduce a 'large connection contract' mechanism for distributors to help address increased connection forecast uncertainty.[95]

B.10. If the Authority were to make changes which materially altered the extent to which distributors could fund the cost of customer connections through capital contributions, the Commerce Commission will have to consider reopening the revenue cap to account for changes in forecast capital expenditure for those distributors that request it. However, it may choose not to reopen if the changes are not sufficiently material.

B.11. Any changes proposed by the Authority to connection pricing will need to carefully consider the impact on distributors subject to P-QR and be considered by both regulatory agencies.

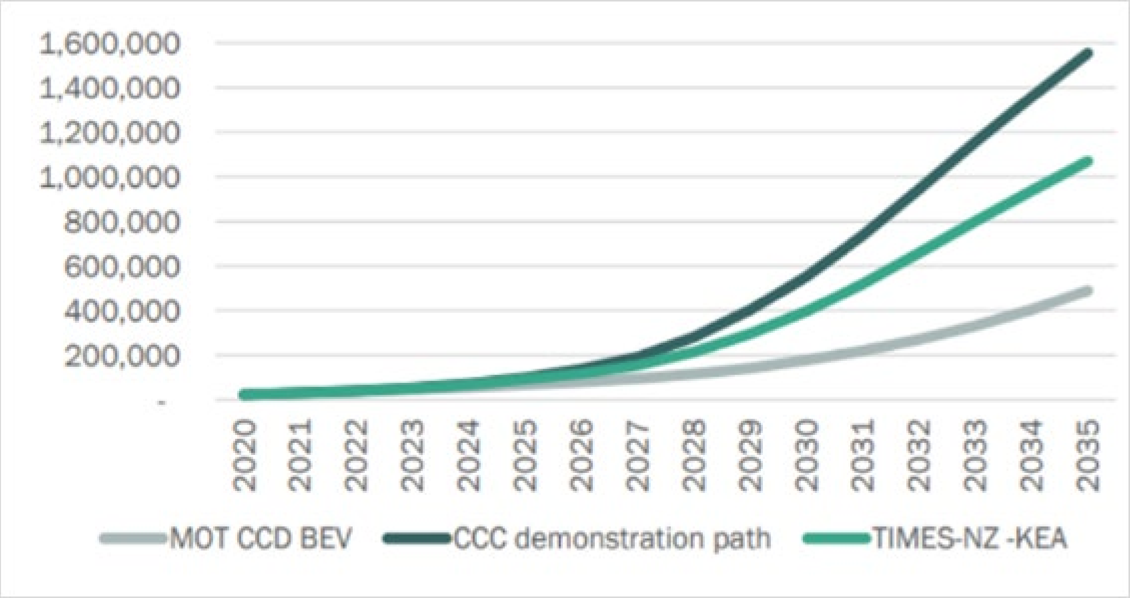
[95] ComCom *Draft Electricity Distribution Services Input Methodologies IM Review 2023 Amendment Determination 2023* 14 June 2023 https://comcom.govt.nz/__data/assets/pdf_file/0027/318663/Draft-Electricity-Distribution-Services-Input-Methodologies-IM-Review-2023-Amendment-Determination-2023.pdf

Appendix C The growth in electric vehicle charging

C.1. The uptake of EVs and the electrification of public transport is forecast to significantly increase over coming decades. This will contribute to the growth in demand for network capacity. This growth is driven by the growing attractiveness of EVs – including falling costs, expanding range of options, improving performance, and improving availability. This is reinforced by government policies such as carbon pricing, feebates and import standards.

C.2. Forecasts for EV uptake from several Government sources are provided below in Figure 9. While there is some variation in these forecasts, the forecasts support a continued material increase in EV uptake.

Figure 9 Battery electric vehicle update scenarios 2020-2035 (excludes plug-in hybrid EVs)[96]

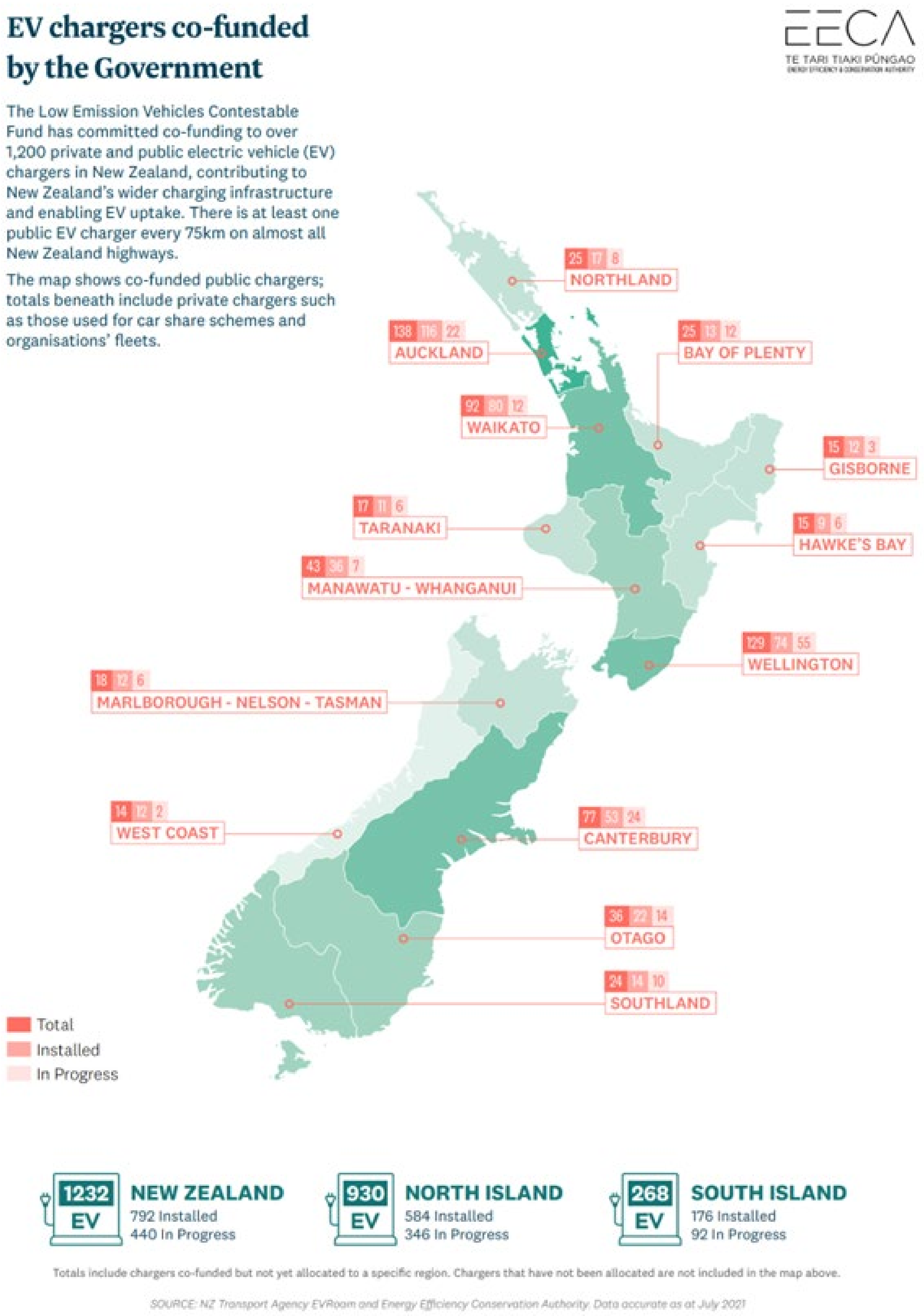


C.3. While EVs can be charged at home or at work, the growth of EVs is still expected to require significant investment in public charging facilities. This is to expand coverage and the range that EVs can travel, reduce congestion or waiting times for a public charger, and improve performance by providing faster chargers.

C.4. Provided below is a map of New Zealand's public EV charging by region that are either installed or in the process of being installed that have been co-funded by government. However, the number of public EV chargers is estimated to only be one per 100 EVs – as discussed in the section on connection pricing. In addition, we understand that a number of these public chargers may require a new or an upgraded network connection to accommodate growth in EVs.

[96] EECA *EV Charging Green Paper* 8 August 2022 (eeca.govt.nz)
https://www.eeca.govt.nz/assets/EECA-Resources/Consultation-Papers/EV-charging-Green-Paper-8-August-2022.pdf
We note that some of these forecasts are precede the clean-car-discount. Actual uptake to 2023 is higher than the curves shown here.

Figure 10: Public EV Charging Co-funded Map[97]



[97] ev-chargers-co-funded-by-the-government.pdf (eeca.govt.nz)

C.5. Issues around public EV chargers are compounded by the expectation that public EV chargers will need to have larger capacity to provide fast-charging facilities that also encourages EV uptake. We note that the majority of public EV chargers only have moderate charge rates. Therefore, there is an expectation that not only will the number of public chargers will increase, but their charging capacity will also need to increase.

C.6. This growth in EV network connections will also increase in the overall load on the wider electricity network. Depending on how this charging is incentivised or managed, it could add load during times of peak demand. Some urban distributors whose networks are already “congested” may have limited spare capacity to accommodate public EV chargers and will require upgrades to support their use. Similarly, if public chargers are required in rural areas to provide greater charging coverage across the country, and these rural areas do not have the electricity capacity to feed them, it may also require upgrades to their wider networks.

C.7. EV charging may also require upgrades to domestic housing connections to allow private charging given a significant amount of charging will also occur at home. Where there is a concentration of residential EV charging a network may require wider network augmentation to support the network and maintain service quality. Although this may be preventable by using ‘smart-charging’ technology and a combination of incentives and tariffs to encourage and reward charging to be managed away from peak demand periods.

C.8. There is also an expected increase in public transport charging facilities for electric buses. These could be quite substantive connections requiring high capacity at central bus depots and bus destination points.

Appendix D Connection Pricing for Transmission

How Transmission pricing allocates upgrade costs to new and exist connections

D.1. For the transmission network, connection costs are allocated in one of three ways:

(a) for spur (connection) assets, upgrade (and renewal) costs are usually allocated to the connected party or parties

(b) if a connection upgrade includes anticipatory capacity, then a portion of costs will be allocated to parties expected to benefit from future use of that capacity – for example, generators that will serve the additional load or load that will consume the additional generation

(c) access seekers pay for their new assets, and for any modifications to existing assets that are necessary to accommodate their connection. Transpower typically offers vendor financing for these capital contributions, with financing rates based on their regulated return – which is low relative to the financing costs otherwise available to most access seekers. This work is also contestable, so access seekers do not have to contract with Transpower (other than for work on existing Transpower assets).

D.2. System growth costs are then allocated through an interplay of nodal prices, settlement residual rebates, and benefit-based charges:

(a) once connected, the access seeker may be allocated their share of benefit-based charges for historical investments

(b) the newly connected access seeker will also face locational marginal prices (LMPs), which include a component signalling the opportunity cost of using the grid

(c) other (existing) grid users are also exposed to the LMPs. If the access seeker increases congestion, then this will increase LMP costs for all affected parties

(d) however, existing users receive rebates that reduce the net cost impact to them of the access seeker's usage. This rebate advantage is time-limited and imperfect, but nonetheless provides some shielding for existing users

(e) if it is economic to upgrade the grid to relieve congestion, then all parties will be allocated these system growth costs in proportion to their benefit. The assessment of benefit can take loss of rebates into account.

D.3. From the above, the costs of transmission network growth investment are allocated across access seekers and existing users in proportion to expected benefits. Existing users are typically allocated a large share of growth costs – especially for less peripheral investments, and allocations are generally highest for parties whose use of the grid has been growing or is forecast to grow.

D.4. A policy that allocated access seekers the full cost of capacity upgrades triggered by their connection would also be less favourable to access seekers. The transmission equivalent is that either:

(a) the asset is not upgraded and congestion costs are allocated through LMPs to all affected users, or

(b) the asset is upgraded, and costs are allocated across all beneficiaries – including the access seeker and existing users.

D.5. In contrast to transmission pricing, policies that allocate capacity upgrade costs to the access seekers who trigger the upgrade can exacerbate coordination challenges (including first-mover disadvantage).

Appendix E Electricity Price Review findings

E.1. The final report of the Electricity price review was issued in May 2019. There are three findings in the area "Improving transmission and distribution" that are relevant to this paper on targeted reform of distribution pricing.

Figure 11 Findings of Electricity Price Review

Section E: Improving transmission and distribution

Our findings:

- Grid operator Transpower and distributors are not making excessive profits
- Delays in agreeing on a fair, efficient and lasting transmission pricing methodology risk undermining market confidence and timely investment
- Distribution pricing does not accurately reflect the cost of distributing electricity at different times of the day and year
- Distribution pricing prevents consumers from benefitting fully from emerging technologies and is slowing the shift to a low-carbon economy
- Distributors cannot access smart metering data on reasonable terms
- Some distributors appear not to be fairly allocating distribution costs between households and businesses
- The Commerce Commission lacks sufficient powers to improve distributors' performance and efficiency

Our recommendations:

- Issue a government policy statement on transmission pricing
- Issue a government policy statement on distribution pricing
- Ensure access to smart meter data on reasonable terms
- Give the Commerce Commission more powers to regulate distributors

Distribution pricing does not accurately reflect the cost of distributing electricity at different times of the day and year

E.2. Our current work programme will continue to address this finding. The adoption of efficient pricing will ensure that the costs of distributing electricity which differ throughout the day and year are reflected into pricing.

E.3. The reference to "different times of the day and year" reflect the traditional load profile with an evening winter peak across most networks in New Zealand. The exception is networks that have large irrigation loads. The evening peak is driven by residential use. Although there is also a morning peak, this is currently lower than the demand in the evening when viewed across most distribution businesses or at an aggregated distribution network level.

E.4. In the sections on peak and off-peak pricing we discussed the granularity of the price signal currently possible and how further options may be available in the future. (An increase in temporal and location granularity may be enabled though change in technology and behaviour in the future).

E.5. In the near term the differences in costs are likely to be simplified into different distribution prices for energy consumed at peak or off-peak periods. Loads that are controllable, (either by traditional control mechanism such as ripple control or alternative arrangement in the future) will not contribute to the cost of providing distribution services at peak times and should therefore benefit from off-peak pricing.

Distribution pricing prevents consumers from benefiting fully from emerging technologies and is slowing the shift to a low-carbon economy.

E.6. Distribution pricing needs to be efficient, signal the economic cost of service provision, to support an affordable transition to a low-emissions economy.

E.7. The sections on peak and off-peak pricing also address the EPR finding that distribution pricing is preventing consumers from fully benefiting from emerging technologies. The adoption of more cost-reflective distribution pricing will send the right signals to support the efficient electrification of process heat, efficient distributed energy resources (DER), (the right level of DER in the right place), and efficient electric vehicle uptake.

Some distributors appear not to be fairly allocating distribution cost between households and businesses.

E.8. While fairness is not part of the Authority's main statutory objective, these observations are also relevant to the efficiency issues discussed in the section on "targeted revenue allocation" between consumer groups.

E.9. The concern is that residential consumers are over-allocated a proportion of shared costs, a result of the cost of supply models (COSM) used by distributors. These models allocate network costs to different consumers groups using allocators. Some distributors use different allocators for different components of network costs. Common allocator applied are number of ICPs, kWh, coincident peak demand, anytime maximum demand, installed capacity.

E.10. While such an allocation of shared costs will still be within the "subsidy-free range" it may not be efficient. The distribution pricing principles require the shortfall in distributors revenue (after revenue from price signalling network costs), should be made up by prices that least distort network use.

E.11. Section 6, Target revenue allocation, deals discusses some of the options that could potentially address this concern.

Appendix F Retailers' incentives to manage network input costs

F.1. Several distributors have introduced 'mild' time-of-use structures – i.e., with relatively small differences between peak and off-peak rates. There has been limited pass-through of these structures by retailers. Some distributors reported that as they lifted the differential retailers expressed more willingness to incorporate the variation.

F.2. Distributors use different price structures for non-mass market customers. Retailers tend to pass though these distribution charges because repackaging risk can be too great and/or energy contracts historically specified the pass through of distribution charges.

F.3. We have explored retailers' response to distribution prices from two perspectives. Firstly, by taking a snapshot of retail offers in the market to understand the extent to which retailer offers included variation in pricing for different periods during the day and how widespread these offers were. This is discussed above in section 8. The second is stylised analysis of the commercial benefit of more cost-reflective retail pricing.

Commercial drivers for cost-reflective retail prices

F.4. If retailers do not adopt cost-reflective prices in response to distribution tariffs it introduces two significant risks for the retailer. Both risks are muted if a large portion of the consumers in a given network area are billed (for energy or network input costs) based on residual profiles.

F.5. These two risks are repackaging error and adverse selection.

(a) Repackaging – To repackage a distribution rate, a retailer creates a blended rate based on assumptions regarding peak versus off-peak consumption across its customers. The retailer then bears the risk that the actual profile in any given month differs from its assumed profile.

(b) Adverse Selection – when re-packaging, a retailer aims to match the peak versus off-peak profile of its own customer base. If some retailers are passing through peak and off-peak structures, then over time there should be migration of less peaky customers to those retailers. This leaves the re-bundling retailer with a peakier customer base, and hence an increasingly uncompetitive position.

F.6. Assuming retailers are billed on actual consumption profiles, we can use a stylised analysis to illustrate the benefit to a retailer of moving their customers to more cost-reflective retail offerings. Below we set out a stylized set of input costs for a reasonably representative residential consumer.

Figure 12 Analysis of retailers' costs for a typical residential TOU customer

Consumption		**8,000**	**kWh**	**per year**		
Off-peak		70%		5,600	kWh	
Peak		30%		2,400	kWh	
Network						
Fixed:	$	1.40	per day	$	511	per year
Off-peak:	$	0.01	per kWh	$	70	per year
Peak:	$	0.08	per kWh	$	180	per year
				$	761	
Energy						
Off-peak:	$	0.08	per kWh	$	448	per year
Peak:	$	0.15	per kWh	$	360	per year
				$	808	
Metering, etc:					$100	per year
Retail margin:					$300	per year
			Total	**$**	**1,969**	**per year**

F.7. In this example, the retailer recovers a retail margin of $300 per year for a customer consuming 8,000 kWh, of which 70% is during off-peak times.

F.8. Now suppose the retailer is offering uniform retail tariffs and competing against retailers offering lower off-peak rates. As a result, over time the retailer disproportionately attracts peaky customers. If the retailer wishes to retain uniform rates, then it must:

(a) increase its rates (making it less competitive)

(b) influence its input costs using non-price methods (eg, through flexibility services),

(c) or reduce its retail margin.

F.9. Below we illustrate the strength of this driver if the retailer begins attracting more peaky customers with only 63% of their consumption off-peak.

Figure 13 Impact on retailers' margin for 'peaky' residential TOU customer

Off-peak	63%		5,040	kWh
Peak	37%		2,960	kWh
Network increase:		$	35	
Energy increase:		$	39	
Margin loss:		**$**	**74**	**25%**

F.10. In this example, the retailer faces higher network but lower energy input costs, reducing its retail margin by $74 per year (25%) for each peaky customer. The commercial pressure that this implies depends on:

(a) whether retailers are billed on actual usage

(b) how strong the differential is between peak and off-peak input costs (network and energy)

(c) whether consumers prefer (and will pay a premium for) uniform usage charges

(d) Consumers are accustomed to traditional tariff structures and may be put off by changes in retail structures. If consumer preference is for uniform structures, then this imposes another hurdle to be overcome, because it is costly for retailers to adopt structures that will reduce their market share. However, consumer preferences can change over time, so this is not a static driver. For example, if consumers came to expect and prefer cheaper off-peak rates, then failing to offer non-uniform structures would become risky for retailers.

(e) How costly it is to implement and service non-uniform pricing.

(f) How quickly consumers seek out and adopt advantageous pricing options.

F.11. Adding complexity to mass-market tariff structures is a non-trivial task that carries direct costs, risk, and opportunity costs. This imposes a hurdle that must be overcome by other drivers.

Appendix G Format for Submissions

Submitter	

Questions
Q1. Are there other options that you think the Authority should consider? Comment
Q2. Do you have any comments on the options outlined? Comment
Q3A. Do you agree that a combination of TOU tariffs and load control (appliance) tariffs would be useful for the smart management of peak demand? Q3B. Do you consider that TOU pricing could have unintended consequences for congestion on the LV network? Q3C.Do you consider that use of shoulder pricing as part of the TOU price structure could be an effective way to mitigate this risk? What other ways could be effective? Comment
Q4. Do you agree with the assessment of the current situation and context for peak period pricing signals? What if any other significant factors should the Authority be considering? Comment
Q5. Do you agree with the problem statement for peak period pricing signals? Comment
Q6. Do you have any comments on the Authority's preferred pricing for peak periods? Comment
Q7. Are there other options you think the Authority should consider for improving peak period pricing? Comment
Q8. Which if any of the above options do you consider would best support distribution pricing reform around peak pricing signals and why? Comment
Q9. Do you agree with the assessment of the current situation and context for off-peak pricing signals? What if any other significant factors should the Authority be considering? Comment
Q10. Do you agree with the problem statement for off-peak pricing signals? Comment
Q11. Do you have any comments on the Authority's preferred pricing for off-peak usage? Comment
Q12. Are there other options you think the Authority should consider for improving off-peak pricing? Comment

Q13. Which if any of the above options do you consider would best support distribution pricing reform around off-peak pricing signals and why? Comment
Q14. Do you agree with the assessment of the current situation and context for target revenue allocation? What if any other significant factors should the Authority be considering? Comment
Q15. Do you agree with the problem statement for target revenue allocation? Comment
Q16. Do you have any comments on the Authority's preferred pricing? Comment
Q17. Are there other options you think the Authority should consider for improving target revenue allocation? Comment
Q18. Which if any of the above options do you consider would best support distribution pricing reform around targeted revenue allocation? Comment
Q19. Do you agree with the assessment of the current situation and context for connection pricing? What if any other significant factors should the Authority be considering? Comment
Q20. Do you agree with the problem statement for connection pricing? Comment
Q21. Do you agree with the Authority's preferred pricing approach for connection charges? Comment
Q22. Do you have any thoughts on the complementary measures mentioned above and to what extent work on these issues could lead to more efficient outcomes for access seekers? Comment
Q23. Are there other options you think the Authority should consider for connection pricing? Comment
Q24. Which if any of the above options do you consider would best support distribution pricing reform in the area of connection pricing? Comment
Q25A. Do you agree with the assessment of the current situation and context for retailer response? What if any other significant factors should the Authority be considering? Q25B. [***for retailers***]: What plans do you have for responding to distribution price signals as distributors reform their price structures? What barriers do you see to responding efficiently? Q25C. [***for distributors***]: What plans do you have to increase the proportion of your customers that face time-varying charges (for example, making TOU plans mandatory for retailers whose end-users have an AMI meter installed)? Comment
Q26. Do you agree with the problem statement for retailer response? Comment

Q27A. Do you have any comments on the Authority's preferred pricing? Q27B. [***for retailers***]: What use do you make of deemed and residual profiles? Please explain the reasons for this. What barriers do you see to phasing out use of deemed and residual profiles? Comment
Q28. Are there other options you think the Authority should consider for retailer response? Comment
Q29. Which if any of the above options do you consider would best support distribution pricing reform in the area of retailer response? Comment

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
AMD	Anytime Maximum Demand
AMI	Advance Metering Infrastructure
AMP	Asset Management Plan
Code	Electricity Industry Participation Code 2010
ComCom	The Commerce Commission
COSM	Cost of supply model
DER	Distributor Energy Resources
DG	Distributed generation
DPPN	Distribution Pricing Practice Note
EDBs	Electricity distribution businesses (distributors)
EECA	Energy Efficiency and Conservation Authority
ENA	Energy Networks Aotearoa
ERANZ	Electricity Retailers' Association of New Zealand
EV	Electric Vehicle
FMD	First Mover Disadvantage
GWh	Gigawatt hour
HH meter	Half-hourly meter
HW	Hot water
HWC	Hot water cylinders
ICE	Internal Combustion Engine
ICP	Installation Control Point
ID requirements	Information Disclosure requirements
IM review	Input Methodologies review
IRIS	Incremental Rolling Incentive Scheme
kWh	Kilowatt hour
kV	Kilovolt
kVa	Kilovolt-amps
LFC Regulations Regulations 2004	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers)
LMP	Locational marginal prices
LRMC	Long-run marginal cost
MEUG	Major Energy User Group
MBIE	Ministry for Business, Innovation and Employment
Ofgem	The Office of Gas and Electricity Markets
TOU	Time of Use
TPM	Transmission Pricing Methodology
UoS	Use of System
UoSA	Use of System Agreement