Ref: 26018

19 May 2026

Electricity Authority | Te Mana Hiko

By email to:
distribution.feedback@ea.govt.nz

Tēnā koutou,

REFORMING NETWORK PRICING FOR DISTRIBUTED GENERATION TO PROMOTE EFFICIENT INVESTMENT

Unison Networks Limited (Unison) and Centralines Limited (Centralines) are consumer-owned electricity distribution businesses serving communities in Hawke's Bay, Taupō, Rotorua, and Central Hawke's Bay. We appreciate the opportunity to submit on the Electricity Authority's consultation paper, Reforming Network Pricing for Distributed Generation to Promote Efficient Investment.

As consumer-owned entities, we operate in the best interests of the communities we serve. Guided by our vision, and values, we strive to deliver economic benefits to both our customers and community shareholders, while championing a sustainable energy future. We are committed to maintaining the right balance between keeping electricity affordable and making strategic investments that secure the long-term reliability and resilience of our network. In all aspects of our operations, we place strong emphasis on meeting industry compliance requirements, ensuring we uphold all relevant standards. This approach not only supports New Zealand's transition to new energy solutions but also enables our communities to access cleaner, smarter, and more flexible energy options, now and for generations to come.

EXECUTIVE SUMMARY

We support the overall direction of the proposed reforms and appreciate the Authority's constructive and collaborative engagement with industry throughout this process. We agree that pricing and connection frameworks must continue to evolve alongside the changing nature of New Zealand's electricity system, as distributed generation (DG), distributed energy resources (DER), batteries, electric vehicles, and increasingly dynamic two-way electricity flows become more prevalent.

We support reforms that seek to improve pricing efficiency, strengthen efficient investment and locational signals, reduce unnecessary barriers to connection, enhance the allocation of costs and benefits associated with distributed generation, support least-cost, whole-of-system outcomes, and modernise regulatory frameworks to reflect a more decentralised and bidirectional network.

While we support the direction of reform, the effectiveness of the framework will depend on how incremental costs are defined and applied in a modern two-way electricity system.

In our view, incremental costs should not be limited to direct connection assets. In an increasingly decentralised system, injection can drive shared and upstream network impacts, including augmentation, voltage management, and operational capability. Where these costs are materially driven by injection demand, they should be capable of being recognised within pricing and reconciliation frameworks.

At the same time, it is critical that any broadening of cost recovery does not dilute efficient locational and capacity-based signals. Pricing frameworks should continue to reflect the cost of network constraints, so that connection and investment decisions support least-cost system outcomes over time.

To support consistent and predictable implementation, we consider the Authority should provide clearer guidance on:
• the boundary between incremental, shared, and residual costs
• the treatment of shared and cumulative network impacts
• the operation of reconciliation methodologies in a two-way system.

Absent this clarity, there is a risk of inconsistent application across distributors, weakened investment signals, and unintended cost allocation outcomes for consumers.

This includes ensuring that non-discrimination provisions can be applied in a way that recognises legitimate differences between legacy and future pricing arrangements.

1. Recognition of the Transition to a Two-Way Electrity System

Historically, the electricity system operated as a one-way delivery model, with power flowing from centralised generation through transmission and distribution networks to consumers. Planning, pricing, and connection approaches were designed around unidirectional flows, with clear cost attribution and predictable bill impacts.

This paradigm is changing as the uptake of rooftop solar, batteries, distributed generation, EVs, and other flexible technologies increases. Distribution networks are increasingly operating as bidirectional systems, with multi-directional flows across shared infrastructure and more complex cost drivers.

In effect, the network is shifting from a one-way highway to a two-way transport system. Changing usage patterns are driving export congestion, reverse flows, voltage management challenges, hosting constraints, and greater operational complexity. Addressing these pressures often requires additional investment and ongoing operating expenditure to maintain reliability and safety for all consumers, including non-exporters.

The Authority is seeking to address several key issues arising from this transition, including:

- inefficient investment and locational signals that increase total network costs reflected in customer bills;
- inconsistent pricing and cost allocation approaches across distributors, reducing transparency and customer confidence;

- “First mover” and “last straw” barriers that distort connection timing and shift costs onto later or non-participating consumers;
- increasing risks of cross-subsidisation between customer groups; and
- the need to modernise pricing and connection frameworks to support a decentralised, bidirectional system while protecting long-term consumer interests.

We agree that these are material issues. However, reform must carefully distinguish between genuinely inefficient barriers and legitimate locational or capacity-based signals that play a significant role in minimising total system costs. Preserving these signals is critical to ensuring that connection and investment decisions remain efficient and do not increase costs borne by existing and future consumers.

In practice, this requires a balanced approach to cost allocation. Where injection materially drives the need for shared network investment, it is appropriate that these costs are reflected in pricing. However, the allocation of these costs should continue to vary by location and network capacity constraints, so that price signals remain meaningful and support efficient siting and investment decisions.

Without this balance, there is a risk that either efficient costs are not recovered or that pricing signals become overly diluted, leading to higher overall system costs over time.

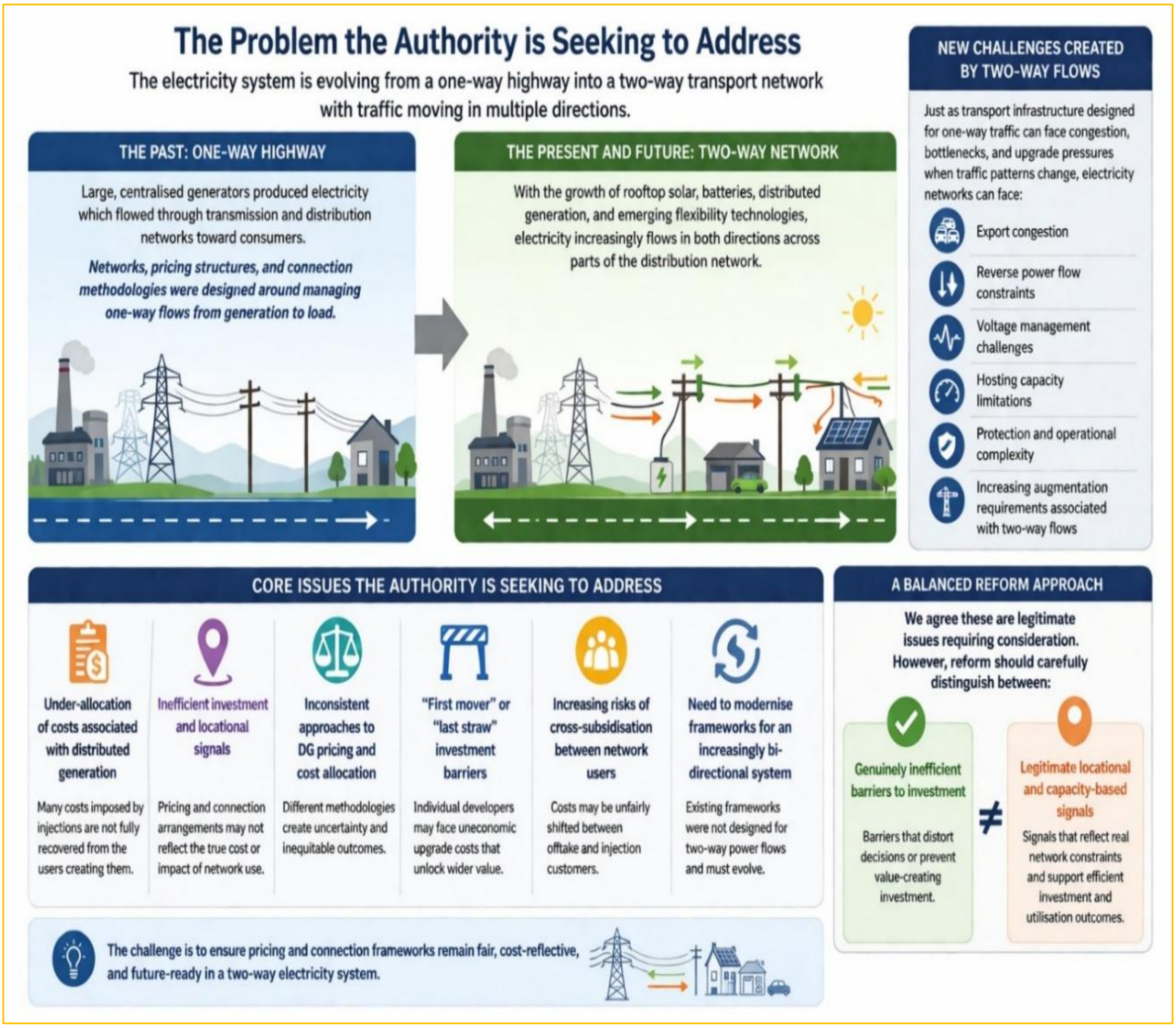
We agree with the Authority that increasing two-way flows can give rise to broader network costs beyond direct connection assets. As exports grow, networks may require upstream reinforcement, enhanced voltage management, operational changes, protection upgrades, export management systems, and augmentation to maintain hosting capacity and service quality.

In an increasingly distributed system, both cost causation and benefit extend beyond immediately attributable connection assets. While localised generation and trading may reduce reliance on parts of the network at certain times, these activities remain enabled and underpinned by the broader interconnected grid.

Accordingly, pricing frameworks should recognise both the direct and indirect benefits users derive from the network, including upstream capacity, resilience, and system support functions. This supports a more complete and economically robust allocation of costs and reduces the risk of under-recovery from users who continue to rely on the network as a backstop.

Many of these costs are shared and system-wide in nature and cannot be readily attributed to individual connections. We therefore support moving beyond an unduly narrow interpretation of incremental cost allocation, provided these preserves efficient locational signals, limits unintended cost socialisation, and protects consumers, particularly those unable to invest in innovative technologies, from avoidable increases in network charges.

Figure 1: illustrates this broader transition from a traditional one-way electricity system toward an increasingly complex two-way network environment and the associated operational and pricing challenges emerging from that transition.



2. Support for the Direction of Reform

We support the Authority's direction to improve cost reflectivity and better align pricing and connection frameworks with the operational realities of a decentralised, two-way electricity system. As network use becomes more dynamic and bidirectional, pricing frameworks must evolve to support efficient investment decisions, transparent cost allocation, and long-term system sustainability.

Consistent with the need for clearer guiding principles outlined in Section 3, pricing and connection arrangements must also support informed customer decision-making. Load customers, DG owners, and emerging prosumers respond to the signals embedded in pricing and connection frameworks when deciding where, when, and how to connect, invest, or adjust consumption and export behaviour. Clear, predictable, and transparent arrangements are therefore essential to align commercial decisions with efficient network utilisation, while limiting distortionary cost socialisation and supporting long-term system outcomes.

As highlighted in Section 3, the challenge is not solely one of increasing cost reflectivity in isolation. Pricing and cost allocation frameworks must remain practicable and workable in application. This requires methodologies that are transparent and understandable, proportionate to the scale and materiality of impacts, sufficiently consistent across distributors, supportive of long-term investment certainty, and aligned with broader system efficiency and consumer affordability objectives.

Sections 4 and 5 build on this foundation by considering how these principles translate into the design of pricing and reconciliation methodologies and their practical application in an increasingly two-way electricity system.

3. Need for Clearer Guiding Principles

The consultation appropriately recognises that distributed generation (DG) can both deliver benefits to, and impose costs on, distribution networks, depending on its location, scale, and manner of connection. However, the effectiveness of the proposed framework will depend on whether the underlying economic and regulatory principles are sufficiently clear, durable, and capable of being applied consistently in a rapidly evolving, two-way electricity system.

However, for the framework to be effective in practice, the Authority should more explicitly articulate how these principles are intended to be applied in a two-way electricity system, including how trade-offs between cost reflectivity and broader consumer outcomes are to be managed. This is critical to ensuring consistent interpretation and implementation across distributors.

In our view, the framework would benefit from a more explicit articulation of how cost reflectivity is to be balanced against other elements of the Authority's statutory objective, including affordability, simplicity and transparency, efficient locational signals, intergenerational equity, avoidance of cross-subsidisation, and the proportionality and feasibility of implementation.

Without clearer guidance on how these trade-offs are to be navigated in practice, there is a material risk of divergent interpretations emerging across distributors. This would reduce predictability for consumers and investors, weaken confidence in pricing signals, and increase both implementation and compliance costs.

We therefore consider that the Authority should complement its principles-based approach with targeted implementation guidance, including worked examples and interpretive material. This is not to replace flexibility, but to ensure that key decision points particularly around cost attribution, reconciliation, and pricing structure are approached in a consistent and economically coherent manner across the sector.

This becomes increasingly important as the system transitions toward more decentralised and bidirectional operation. In this environment, cost drivers are more complex, impacts are often cumulative and shared, and traditional one-way frameworks are less able to capture the true drivers of network investment and operation.

However, for the framework to be effective in practice, the Authority should more explicitly articulate how these principles are intended to be applied in a two-way electricity system, including how trade-offs between cost reflectivity and broader consumer outcomes are to

be managed. This is critical to ensuring consistent interpretation and implementation across distributors.

Clarifying incremental cost in a two-way system

A central issue is the need for the Authority to clarify how incremental costs should be interpreted in a two-way electricity system. Under current approaches, incremental cost is often narrowly defined as direct, connection-specific assets. However, this does not reflect how costs arise in practice within a decentralised and increasingly dynamic network.

In a two-way system, injection can materially drive:

- shared network augmentation and upstream reinforcement;
- operational and capability investments (including voltage management, protection, and system visibility); and
- future capacity requirements resulting from cumulative impacts across multiple connections.

While these costs may not be triggered by a single connection, they can nevertheless have a clear and demonstrable causal relationship to incremental injection demand. A workable framework must therefore allow for the recognition of both direct and shared incremental costs where this relationship exists.

At the same time, appropriate boundaries must be maintained. Costs associated with broader asset replacement, resilience, or general network renewal should not be attributed to injection unless they are materially driven by injection-related requirements. Clearer guidance on these boundaries is essential to avoid both under-recovery (leading to cost shifting) and over-recovery (which distorts efficient price signals).

The Authority should therefore clarify that incremental cost frameworks are not limited to direct connection assets but may include shared and upstream network costs where there is a clear and causally linked relationship to injection demand.

Future-focused, market-agnostic pricing design

Distribution pricing must be designed to remain fit-for-purpose as market arrangements evolve, including in a multi-trader retail (MTR) environment. Pricing design should not be constrained by current retailer structures or a single-retailer paradigm, as doing so risks embedding assumptions that may not hold in an evolving MTR or multi-participant market environment.

Instead, pricing should be capable of evolving over time to reflect the costs associated with several types of network usage and user behaviour, including increasingly dynamic two-way flows, distributed generation, storage, and local energy trading. Anchoring pricing design to underlying cost drivers, rather than to transitional market constructs, will better support efficient investment and ensure the framework remains durable as market arrangements continue to change.

The Authority should ensure that pricing principles and guidance explicitly enable market-agnostic, future-focused pricing structures that can adapt as market arrangements evolve.

Unbundling and service-based pricing

This is particularly important in an MTR environment, where different services may be separately valued, contracted, and optimised. Without unbundling, pricing risks misallocating costs across fundamentally different usage types and weakening efficient signals.

Pricing should therefore, where practicable, reflect the distinct services provided by the network, such as capacity availability, reliability and back-up supply, congestion management, and local hosting capability. Bundled pricing approaches can obscure underlying cost drivers and dilute the effectiveness of price signals.

By contrast, service-based pricing enables clearer alignment between:

- the benefits users receive;
- the costs their behaviour imposes; and
- the signals required to support efficient investment and utilisation decisions.

This alignment becomes increasingly critical as system complexity increases and multiple market participants interact with the network in diverse ways.

Recognising upstream enabling and backstop services

The growth of localised generation and trading, including house-to-house or street-to-street exchanges does not reduce reliance on the interconnected distribution and upstream grid. Rather, these activities remain fundamentally enabled and supported by it.

The broader network continues to provide essential services, including:

- system balancing and coordination.
- security and quality of supply
- resilience and contingency support
- access to wider system capacity when local resources are insufficient.

These services constitute a form of network “backstop” capability that provides ongoing value to all users, including those operating at the edge of the network.

If these benefits are not appropriately recognised within pricing frameworks, there is a risk that users particularly those engaged in local trading under-contribute to the costs of the network they continue to rely on. Over time, this would result in inefficient cost shifting, weakened investment signals, and outcomes that are not consistent with the long-term benefit of consumers.

Allocating shared and upstream costs to reflect benefits

As participation in distributed generation and local energy trading increases, some users may appear to reduce their reliance on the network under normal operating conditions, while continuing to depend on it for back-up, balancing, and access to broader system capacity.

Pricing frameworks must therefore ensure that shared and upstream network costs are allocated in a way that reflects the benefits derived from these services, including by edge participants.

This is necessary to:

- avoid unintended cost shifting and free-riding;
- maintain fairness across customer groups; and

- preserve efficient signals for both network investment and customer behaviour.

A failure to do so would risk undermining the financial sustainability of the network and distorting investment decisions across both load and generation.

The Authority should therefore ensure that the framework explicitly enables these costs to be recognised within pricing and reconciliation methodologies, where supported by a clear and demonstrable link to network use.

Implementation implications for the Authority

To support effective implementation, the Authority should ensure that:

- incremental cost guidance explicitly includes shared and upstream impacts where causally linked to injection;
- pricing frameworks are not constrained by current retailer models and remain adaptable to MTR environments;
- unbundled, service-based pricing approaches are enabled where they improve cost reflectivity; and
- upstream network benefits and backstop services are appropriately recognised in cost allocation methodologies.

Providing this clarity will improve consistency across distributors, reduce regulatory uncertainty, and better support efficient outcomes over time.

4. Reconciliation methodologies in an evloving electricity system

Consistent with the need for clearer guiding principles outlined above, further clarity is needed on the definition and treatment of “incremental costs” within the proposed reconciliation methodology, particularly as the system transitions from a one-way to a two-way network model. Without this clarity, there is a risk that reconciliation outcomes do not fully reflect the underlying drivers of cost in a modern electricity system.

The current framework was developed for unidirectional flows, where connection impacts were localised and costs could be readily attributed to individual connections. As networks evolve, increasing uptake of DG, storage, EVs, and flexible technologies is driving more dynamic, decentralised, and bidirectional flows. Network costs in the future will be shaped by cumulative system interactions, shared capacity constraints, and broader performance considerations.

In this context, the boundaries of “incremental cost” are less distinct. For example, a new injection connection may not independently trigger a network upgrade but may contribute to cumulative exports that exceed hosting capacity on a feeder or substation. In response, the distributor may need to undertake upstream reinforcement or implement export management capability.

Under a narrowly defined incremental cost framework, these costs may not be recoverable from any individual connection, despite being materially driven by the aggregate impact of injection. This highlights the importance of recognising shared and cumulative cost drivers within reconciliation methodologies.

This also requires careful consideration of the data requirements, system capability, and administrative complexity associated with implementing more granular cost allocation methodologies, particularly as networks become more dynamic and data intensive.

It is also important that the framework remains compatible with storage and other flexible technologies, which can significantly influence network utilisation and cost drivers. Reconciliation methodologies should therefore be sufficiently adaptable to recognise these effects without introducing unintended biases.

Section 5 outlines the practical implications of these issues and identifies areas where further clarification would support consistent implementation.

Figure 2: *illustrates this issue, highlighting that the impacts associated with two-way electricity flows may extend well beyond direct connection assets and may require broader network capability and operational investment to accommodate injections safely and efficiently.*

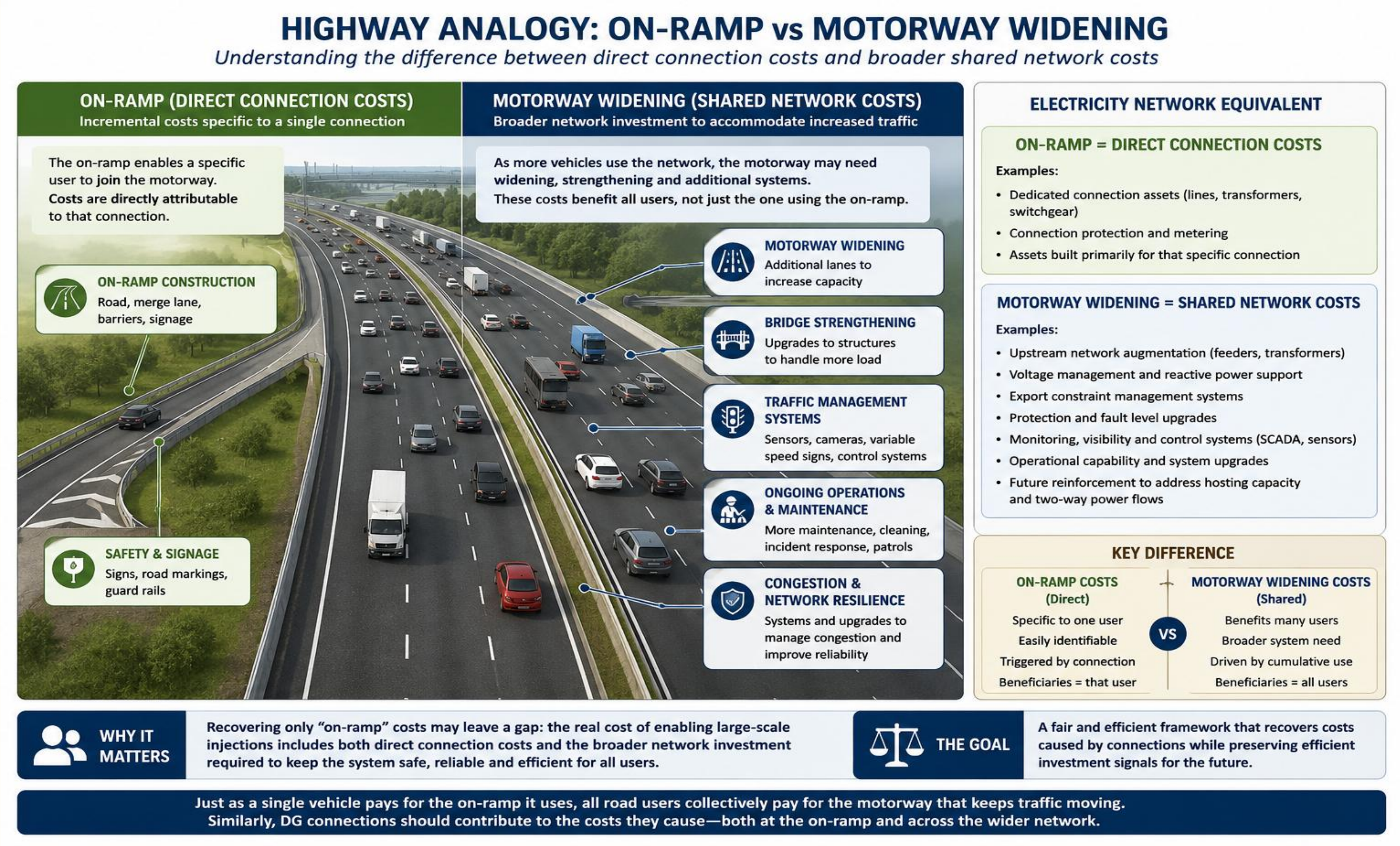


Table 1: Key Issues and Clarification Sought on Incremental Costs and Reconciliation

Topic Area	Submission Concern	Why It Matters	Questions for the Authority
Definition of Incremental Costs	The paper does not clearly define the practical boundary between incremental, shared-incremental, and residual/shared network costs.	Lack of clarity may lead to inconsistent interpretation and implementation across distributors.	How does the Authority intend to define and distinguish between incremental, shared-incremental, and residual/shared network costs in a modern two-way electricity system?
Scope of Recoverable Costs	It is unclear which network impacts and cost categories are intended to be recoverable through reconciliation methodologies.	Uncertainty may create ambiguity for distributors regarding prudent and efficient cost recovery for DG-related investment.	Which categories of network costs are intended to be recoverable, including upstream augmentation, voltage management, export management systems, protection upgrades, operational systems, monitoring capability, and future reinforcement?
Shared Network Impacts	Many DG-related impacts arise progressively across shared infrastructure rather than through standalone connection assets.	Costs that are shared in nature may nevertheless be materially driven by incremental injection demand.	How should distributors treat costs that are partly shared in nature but are materially driven by incremental injection connections?
Under-Recovery Risk	Recovery mechanisms may be limited to narrowly defined direct incremental costs.	This may create risks of under-recovery of prudent and efficient investment required to accommodate DG connections.	How does the Authority view the risk of under-recovery where DG connections drive broader shared network impacts that extend beyond direct connection assets?
Cross-Subsidisation	Excluding broader network impacts from recovery may shift costs onto existing consumers.	This may result in inequitable cost outcomes and inefficient cross-subsidisation between customer groups.	How does the Authority intend to ensure cost allocation outcomes remain equitable where DG materially contributes to shared augmentation requirements?
Locational Investment Signals	Excessive socialisation of augmentation costs may weaken efficient locational and capacity-based signals.	Developers respond to commercially meaningful network constraints and hosting-capacity limitations.	How does the proposed framework preserve efficient locational and capacity-based investment signals, particularly in constrained parts of the network?
Cumulative Injection Impacts	Multiple DG projects may progressively contribute to shared augmentation over time.	Individual projects may not independently trigger upgrades but may collectively drive significant network investment.	How does the Authority envisage reconciliation methodologies operating where cumulative

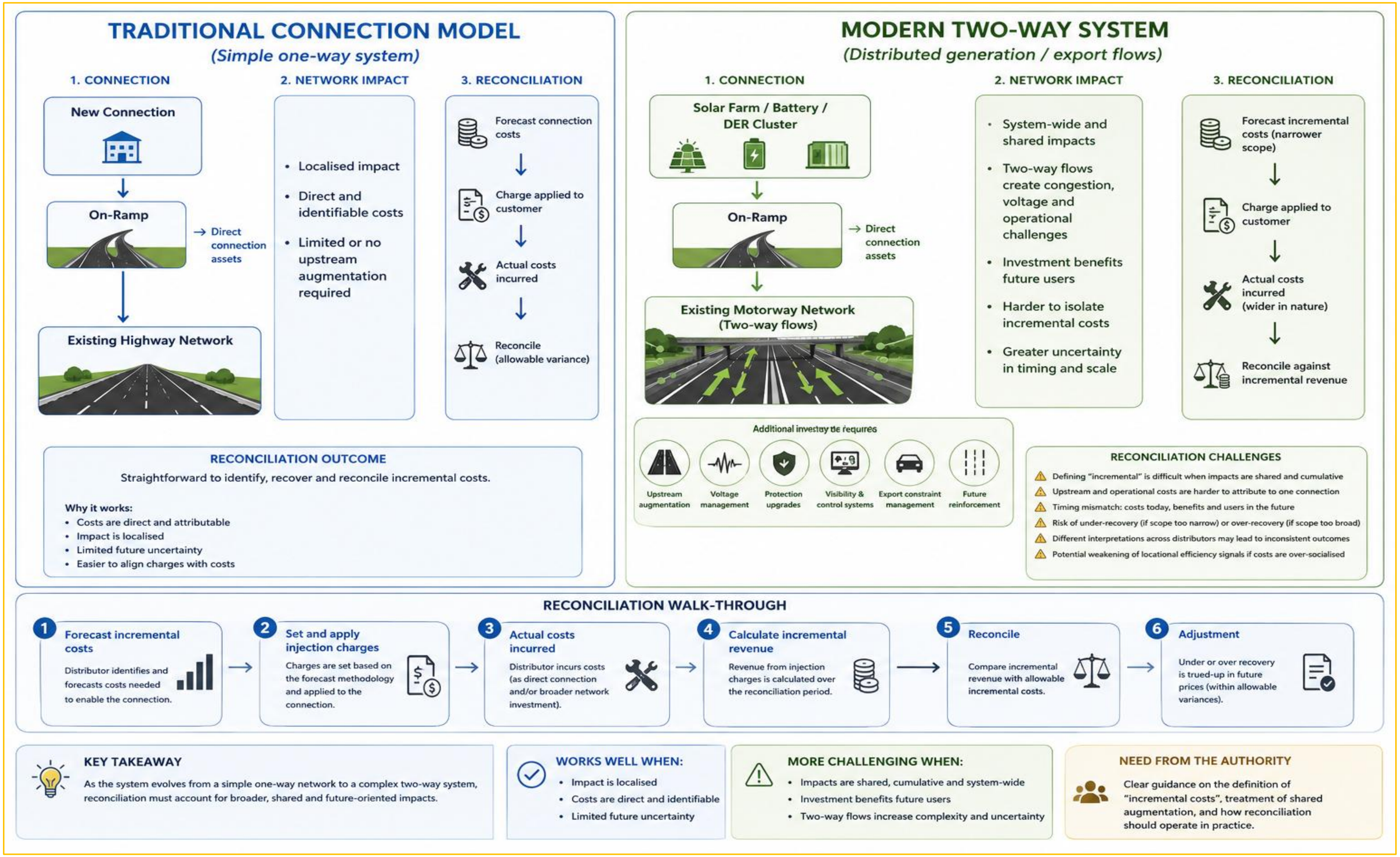
			injections from multiple DG projects progressively contribute to shared augmentation requirements?
Two-Way Network Complexity	Traditional one-way cost allocation frameworks may not reflect modern network characteristics.	Two-way flows create broader operational, voltage, protection, and hosting-capacity impacts.	Does the Authority consider that additional implementation guidance or principles are required to support consistent treatment of incremental and shared network costs in a two-way system?
Highway Analogy – On-Ramp vs Motorway Widening	The framework may focus on recovering the cost of the "on-ramp" connection while excluding broader "motorway widening" costs.	Direct connection assets are distinct from broader shared investment required to accommodate increased and cumulative two-way flows.	How does the Authority intend to distinguish between direct connection ("on-ramp") costs and broader shared network augmentation ("motorway widening") costs associated with enabling increased two-way flows?
Predictability and Regulatory Certainty	The proposal leaves material scope for interpretation.	Uncertainty may contribute to inconsistent methodologies and disputes over time.	Would the Authority consider publishing additional guidance, worked examples, or principles to support more consistent implementation across distributors?
Role of Storage in Managing Network Impacts	The reconciliation and pricing framework does not clearly recognise the role of storage in mitigating injection-driven impacts.	Storage can shift exports away from constrained periods, improve utilisation of existing capacity, and reduce or defer shared augmentation.	How does the Authority intend the reconciliation and pricing frameworks to treat storage where it materially reduces incremental and shared network costs and supports more efficient network utilisation?

Our position on the issues above

Across the issues outlined in Table 1, a consistent theme is the need for the framework to recognise that:
• network impacts from injection are often cumulative and shared;
• cost drivers extend beyond direct connection assets; and
• reconciliation methodologies must operate at a system level, not solely at an individual connection level.

We therefore consider that guidance should support approaches that allow for the recovery of costs where there is a material and demonstrable link to injection demand, while maintaining transparency and preserving efficient investment signals.

Figure 3: the challenges of the reconciliation of injection connection costs



5. Implications for Implementation in a Two-Way Electricity System

Building on the issues outlined above, the following considerations highlight the practical implications for implementing reconciliation methodologies within an increasingly decentralised, two-way electricity system. As network complexity increases, the ability to consistently define, attribute, and recover incremental and shared costs becomes more challenging, with important implications for pricing outcomes, investment signals, and consumer impacts.

The existing framework has operated effectively under a traditional one-way network paradigm, where connection impacts were localised, augmentation requirements were more readily identifiable, and costs could be more directly attributed to individual connections. As the system evolves to accommodate higher penetrations of DG, batteries, electric vehicles, and dynamic export behaviour, the practical application of incremental costs becomes materially more complex.

In practice, accommodating injection connections may require investment well beyond direct connection assets. Depending on location, scale, and cumulative impacts, distributors may need to undertake shared upstream augmentation, enhanced voltage management capability, export congestion management measures, protection and fault-level upgrades, improved network visibility and control systems, changes to operational network management practices, and future reinforcement to address hosting capacity limitations and cumulative two-way power flows. Many of these impacts are shared, cumulative, and system-wide in nature, making it increasingly difficult to isolate costs to a single connecting party or a narrowly defined category of “incremental” expenditure.

Against this backdrop, there is a risk that a narrowly defined methodology may under-represent the true network impacts associated with injection connections. This could lead to inconsistent cost recovery outcomes across distributors, weaken efficient locational and capacity-based investment signals, increase the risk of inefficient cross-subsidisation, and result in divergent interpretations of recoverable costs. Over time, these outcomes may not best promote the economically efficient investment and operation of distribution networks or the long-term benefit of consumers.

We also consider it important that the proposed amendments do not unintentionally disincentivise the efficient deployment of storage technologies. Storage has the potential to mitigate injection-driven network impacts by shifting exports away from constrained periods, improving utilisation of existing network capacity, and reducing the need for shared augmentation. Where reconciliation and pricing methodologies appropriately recognise these effects, they can support more efficient investment and operational outcomes. Conversely, if incremental cost frameworks do not adequately account for the system benefits of storage, pricing signals may discourage investment that would otherwise reduce network costs and support long-term consumer benefits.

To support implementation and promote consistent, predictable outcomes across the sector, Table 1 above summarises the key areas where further clarification would be beneficial, the implications of ongoing uncertainty, and specific questions for the Authority’s consideration.

6. Assessment of Proposed Pioneer Scheme Amendments Against Policy Objectives

We consider that any pioneer scheme design should be aligned with the Authority's objectives of promoting efficient investment, maintaining predictable and transparent pricing signals, and ensuring technology-neutral treatment of connection applicants.

Both load and DG developers respond to network pricing, capacity allocation processes, and connection cost signals when making siting and investment decisions. In practice, developers may adjust project timing, staging, scale, or configuration in response to connection frameworks and pioneer incentives. While such responses are commercially rational, poorly calibrated pioneer arrangements risk distorting efficient locational signals by encouraging decisions that prioritise scheme eligibility rather than long-term network efficiency.

The introduction of multiple pioneer schemes with differing rules, eligibility thresholds, or timeframes, particularly where these apply asymmetrically to load and generation, would increase the risk of reduced predictability and consistency in connection outcomes. This could encourage strategic sequencing or staging of projects, increase administrative complexity, and undermine confidence in the stability of connection cost signals over time.

From an efficiency perspective, it is important that pioneer arrangements clearly distinguish between:

- genuine first-mover disadvantages that reflect inefficient barriers to entry; and
- legitimate cost signals that appropriately reflect scarce network capacity or the costs of enabling additional connections, whether for load or generation.

Over-socialisation of augmentation costs, or the introduction of multiple overlapping schemes, risks diluting these signals and transferring costs to existing consumers in ways that are not clearly efficiency-enhancing.

Against this backdrop, we question whether introducing additional pioneer schemes with materially different parameters would better achieve the Authority's objectives, or whether a simpler, more unified, and technology-neutral approach would effectively preserve efficient investment incentives, provide predictable outcomes for developers, and protect consumers from unintended cost transfers.

On balance, we do not consider that introducing multiple or expanded pioneer schemes is necessary to achieve the Authority's objectives. A simpler, technology-neutral approach that is applied consistently across load and generation is more likely to:

- preserve efficient locational investment signals;
- reduce administrative complexity and strategic behaviour; and
- limit unintended cost transfers to existing consumers.

Pioneer arrangements should therefore remain narrowly targeted to address genuine first-mover disadvantage, rather than being used as a broader cost allocation mechanism.

7. Consideration of Proposed Amendments Against Policy Objectives

We have assessed the proposed amendments against the Government's broader energy policy objectives in the table below, the Authority's stated policy rationale, and practical implementation considerations for distributors operating within an increasingly decentralised electricity system.

Table 2: Consideration Against Government Policy Statement (GPS on Electricity, October 2024).

GPS Clause	Consideration of Proposed Amendments	Our Response / Recommended Position
14(a) Efficient network pricing – enabling lowest-cost solutions (including demand response and flexibility)	The proposal updates distribution pricing settings to better reflect the network impacts of injection, including enabling cost-reflective signals that support demand-side response, flexibility solutions, and non-network alternatives were efficient.	Support, with refinement. Efficient pricing requires that both direct and shared network costs associated with injection are appropriately reflected in pricing signals. This strengthens incentives for least-cost solutions, including flexibility and storage. However, insufficient clarity on incremental vs shared cost boundaries risks weakening these signals and may limit the ability of pricing to drive efficient non-network alternatives over time. Clearer guidance is required to ensure pricing frameworks fully support system-wide optimisation.
14(b) Efficient investment in new electricity consumption (including electrification of transport and process heat)	The proposal seeks to reduce cross-subsidisation by ensuring consumers do not bear costs driven by injection, thereby improving the efficiency of price signals faced by load customers and supporting electrification.	Support in principle. Reducing cross-subsidisation improves price signals for electrification and consumption investment. However, the framework must avoid over-socialising injection-driven costs, which could undermine efficient consumption signals. Efficient cost allocation and recovery is essential to ensure that load customers face accurate price signals reflecting underlying system costs, supporting economically efficient electrification outcomes.
15(a) Role of the Electricity Authority in setting pricing principles and structures	The proposal amends the Code to introduce updated mandatory pricing principles for distribution pricing structures relating to injection connections.	Support. Updating Code principles is appropriate to reflect the transition to a two-way electricity system. However, to ensure consistent implementation across distributors, the Authority should complement principles-based regulation with clearer supporting guidance and worked examples, particularly in relation to incremental cost definition, reconciliation, and treatment of shared network impacts.
31(e) Government consideration of thresholds for EDB investment in generation (non-discrimination considerations)	The proposal introduces requirements for distributors to set charges that do not discriminate based on ownership, including where the distributor has interests in generation assets.	Support. Non-discrimination provisions are important to maintain investor confidence and ensure competitive neutrality. These safeguards are particularly relevant as policy settings evolve to potentially enable greater EDB participation in generation. Clear and enforceable non-discrimination requirements help ensure pricing reflects network impacts rather than ownership structure, supporting efficient investment outcomes.
32 Collaboration across regulatory agencies (EA, Commerce Commission, MBIE)	The proposal has been developed with engagement across agencies and interacts with Commerce Commission regulation of electricity lines services and broader government policy settings.	Support, with emphasis on ongoing coordination. Alignment across regulatory frameworks is critical. In particular, the interaction between Electricity Authority pricing rules and Commerce Commission regulation of cost recovery (e.g. ID/DPP frameworks) must be coherent to avoid conflicting incentives or under-recovery risks. Ongoing collaboration with MBIE is also important, particularly where reforms intersect with generation investment thresholds and broader energy policy objectives.

8. Conclusion

We support the Authority's objective of improving cost reflectivity and promoting economically efficient investment and use of distribution networks in the context of increasing distributed generation. We agree that pricing and reconciliation frameworks should ensure that injection connections face appropriate signals reflecting the costs they impose on the network, consistent with the long-term benefit of consumers.

However, as distribution networks transition toward more decentralised and bi-directional operation, the practical application of incremental cost reconciliation becomes materially more complex. Many network impacts associated with injections are shared, cumulative, and system-wide in nature, and may not be readily captured through narrowly defined or connection-specific reconciliation approaches.

In our view, the key priority is ensuring that reconciliation and pricing frameworks appropriately reflect the shared and system-wide nature of network impacts in a two-way electricity system.

This requires clearer guidance on the treatment of incremental, shared, and residual costs, and how these concepts should be applied in practice. Without this clarity, there is a risk of inconsistent implementation, inefficient pricing signals, and unintended cost allocation outcomes for consumers.

In particular, the timely publication of supplementary guidance, worked examples, and interpretive material would materially support consistent implementation across distributors, reduce the risk of divergent approaches, and improve transparency for connecting parties.

We would welcome continued engagement with the Authority as these reforms develop further. No part of our submission is confidential.

Ngā mihi nui,

JASON LARKIN / TARRYN BUTCHER
GM COMMERCIAL AND REGULATORY / REGULATORY MANAGER
[redacted]

Appendix A Format for submissions

Reforming distributed generation pricing to promote efficient investment.

Please email your submission to **distribution.pricing@ea.govt.nz** by 5pm, Friday 15 May 2026

Name	Tarryn Butcher
Organisation	Unison and Centralines

Questions	Comments
Q1. Do you agree with the background and context summary above? Why? Is there additional background, evidence, or context relevant to the proposals in this paper?	Yes, we agree with the background and context summary. We consider relevant is that the costs and benefits associated with distributed generation are often highly location- and time-specific. In practice, material network impacts typically arise during recognised peak periods and in constrained locations, while injections outside these conditions may deliver little or no network benefit. This affects how incremental costs, deferred investment benefits, and efficient pricing signals should be assessed and allocated. We also note that existing tariff structures, particularly for residential consumers, can include significant variable components, allowing DG customers to reduce network charges without a corresponding reduction in underlying network costs. This underscores the importance of frameworks that reflect cost causation, preserve efficient capacity-based signals, and avoid unintended cost redistribution as DG uptake increases. Finally, clearer implementation guidance and worked examples, particularly for residential, seasonal peak, and feeder-level scenarios, would support more consistent and practical implementation across distributors.
Q2. Do you agree there are workability challenges with defining incremental costs under the current DGPPs? Why, why not? Are there any additional challenges not discussed above?	There are workability challenges with defining incremental costs under the current DGPPs. The existing framework adopts a narrow, asset-specific interpretation focused primarily on direct connection assets. This does not reflect the reality that distributed generation increasingly drives shared and capacity-related network impacts, including upstream reinforcement, operational changes, and future augmentation. As a result, it is difficult to recognise costs that are materially driven by injection growth but not attributable to a single connection. This creates risks of under-recovery, cross-subsidisation, and weakened investment signals. Clearer guidance that enables incremental costs to include shared and capacity-driven impacts would improve workability and support more accurate cost allocation.

Questions	Comments
Q3. Do you agree the current DGPPs cause costs and benefits to be under-allocated to injection connections, which can cause the issues listed above? Why?	The current DGPPs tend to under-allocate both costs and benefits associated with injection connections by focusing narrowly on direct connection assets. In practice, distributed generation can drive broader shared network and operational impacts that are not fully captured under existing settings. This can result in under-recovery of efficient costs, increased cross-subsidisation, and weakened locational and investment signals as injection volumes increase.
Q4. Do you consider it remains appropriate to regulate injection pricing methodologies? Why?	Given the characteristics of distribution networks and the increasing materiality of injection-related impacts, some level of regulatory oversight remains appropriate. However, regulation should be principles-based and enabling, allowing distributors flexibility to reflect local conditions while avoiding overly prescriptive or inefficient outcomes.
Q5. Do you consider that consumers should remain residual payers? Why? Are there any additional economic concepts that should be considered in our reform of the DGPPs?	Consumers should remain residual payers only where costs cannot be attributed to specific connections or activities. This should not justify systematic under-recovery of network costs driven by injection connections or unintended cost socialisation. Key economic concepts that should remain central include cost causation, capacity-based pricing signals, avoidance of cross-subsidisation, and intergenerational equity.
Q6. Do you consider that reframing the incremental cost rule to a requirement that charges 'must reflect a reasonable estimate of' rather than 'must not exceed' incremental costs is appropriate? Why?	We support reframing the incremental cost rule to require charges to reflect a "reasonable estimate" of incremental costs. This better reflects real-world network planning, where impacts are often shared, cumulative, and capacity-driven rather than directly attributable to a single asset. It improves workability and supports more accurate cost allocation while maintaining safeguards against over-recovery. Clear supporting guidance will be important to ensure consistent interpretation across distributors.
Q7. Do you consider that the proposed amendments to language and framing would support more efficient pricing? Why?	The proposed amendments better recognise the transition to a two-way electricity system and place greater emphasis on capacity-related impacts. This supports more efficient pricing outcomes. However, clearer implementation guidance will be required to support consistent interpretation and application across distributors.
Q8. Do you consider that a non-prescriptive, enabling approach to capacity pricing is appropriate at this stage? Why?	A non-prescriptive approach is appropriate given the diversity of distribution networks and evolving two-way use. An enabling framework allows distributors to adopt proportionate and tiered approaches, ensuring that pricing reflects the scale and materiality of network impacts without imposing unnecessary complexity.

Questions	Comments
Q9. Do you consider that the proposed extension of the pioneer scheme for load connections would help address position-in-queue issues for injection connections? Why?	Pioneer schemes should remain targeted and carefully designed to address genuine first-mover disadvantages, without weakening efficient locational signals or introducing unintended cost socialisation.
Q10. Do you consider that pioneer schemes should also cover network injection capacity? Why?	We agree in principle that extending pioneer schemes to injection capacity could improve fairness and investment efficiency where upgrades provide shared benefits. However, this should be applied selectively, with clear design parameters to preserve cost causation and efficient investment signals.
Q11. Do you consider that the proposed non-discriminatory pricing requirements would improve confidence that investors are safeguarded from discriminatory pricing? Why?	Non-discriminatory pricing requirements will improve transparency and investor confidence, particularly as greater discretion is introduced. Further clarification is required to support practical implementation, particularly in relation to legacy arrangements (see Q30).
Q12. Do you agree with the proposed application provisions, in particular with regard to opting out, retrospectivity and secondary networks? Why?	We broadly support the direction of the application provisions. However, further clarity is required on the interaction between Parts 6 and 6B, particularly for injection connections involving secondary networks. Clear and consistent application pathways are important to avoid process gaps and unintended outcomes.
Q13. Do you agree with the proposed commencement provisions above? Why?	We support the proposed commencement provisions, provided sufficient transition timeframes and early guidance are available to enable practical and orderly implementation.
Q14. Do you have any suggestions for how we can most effectively support successful implementation?	Successful implementation will depend on: • supplementary guidance and interpretive material • worked examples across a range of connection types and scenarios. • ongoing engagement with industry during transition These measures would support consistency, reduce uncertainty, and improve practical application.
Q15. Do you have any suggestions for effective monitoring and reporting, including proposed changes to charge reconciliation requirements?	Monitoring and reporting should focus on material pricing outcomes and network impacts, while avoiding unnecessary compliance burden. Reconciliation requirements should remain proportionate and aligned with the practical ability to identify and attribute incremental costs over time.
Q16. Do you agree it is appropriate to give distributors relatively wide discretion as to how they implement capacity charges for injection connections? Why?	Distributors should retain discretion to implement capacity charges, given variation in network topology and constraint profiles. An enabling approach allows pricing to reflect local conditions and ensures proportionality to network impacts.

Questions	Comments
Q17. Do you agree that for larger connections a more bespoke approach that accounts for dependability and mitigates risks such as over-injection or inefficient payments is more appropriate than the prescriptive broad-based approach used for residential and small business consumers? What do you consider such an approach should look like?	Yes, a more bespoke approach is appropriate for larger connections due to differences in scale and impact. A tiered framework would improve proportionality, with: • standardised approaches for small connections • location- and capacity-based pricing for larger connections This would better reflect network impacts while maintaining workability.
Q18. Is there any specific guidance that would be particularly helpful for distributors implementing capacity charges for injection?	Guidance would be particularly valuable on: • the scope of incremental and shared costs • treatment of cumulative and capacity-driven impacts • valuation of deferred or avoided investment • reconciliation with existing tariff structures This would support consistent implementation across distributors.
Q19. Do you consider that inconsistent treatment of transmission connection charges for large generation projects may distort investment? Why?	Inconsistent treatment of transmission and distribution charges can distort investment decisions by weakening cost-reflective signals and influencing siting decisions.
Q20. Do you have a view on the best option to address the connection charge distortion issue? Please explain your rationale.	Approaches that better align connection charges with ongoing network use would improve efficiency. This includes recognising upstream use and operational costs where appropriate, reducing reliance on fully upfront contributions while preserving efficient signals.
Q21. Do you consider that the restriction on recognising transmission benefits should be reconsidered if the other proposed Code amendments are made? Why?	Where distribution investment delivers transmission benefits, restrictions on recognising those benefits may distort efficient outcomes. Greater alignment would improve consistency and support better investment decisions.
Q22. Are there any other matters that you consider important for us to take into account in our reform of the DGPPs?	Additional considerations include: • interactions with existing tariff structures • fairness between customers with and without DG • maintaining practicality and affordability as uptake increases
Q23. Do you have any comments on the consumer impact analysis methodology or findings?	Consumer impacts will depend heavily on implementation choices and local conditions. More granular analysis, particularly at residential and feeder levels would improve transparency and robustness.

Questions	Comments
Q24. Do you agree with the objectives of the proposed amendment? If not, why not?	We agree with the objectives of improving pricing efficiency, supporting efficient investment, and modernising pricing frameworks for a two-way system.
Q25. Do you agree the benefits of the proposed amendments would outweigh the costs?	The benefits are likely to outweigh the costs, provided the framework is enabling, proportionate, and supported by clear guidance.
Q26. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	Yes, the proposed amendments strike a better balance between cost reflectivity and flexibility than more prescriptive alternatives.
Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	In our view, the proposed amendment is consistent with the Authority's statutory objective and therefore complies with section 32(1).
Q28. Do you consider that the Authority's preferred high-level settings for injection pricing are consistent with the distribution pricing principles? Why?	The preferred settings are broadly consistent with distribution pricing principles, including cost reflectivity, efficiency, and avoidance of cross-subsidisation, provided they are implemented in a practical and proportionate way.
Q29. Do you consider that consolidating distribution pricing methodology requirements into Part 6B would improve clarity and consistency? If not, why?	Consolidating methodology requirements into Part 6B would improve clarity and consistency, provided transitional issues and interactions with Part 6 are clearly addressed.

Questions	Comments
Q30. Do you have any comments on the drafting of the proposed amendment?	We support the direction of the proposed drafting; however, further clarification is required to improve workability and consistency. Key areas include: • terminology and definitional alignment • interaction between Parts 6 and 6B • scope of recoverable incremental and shared costs • operation of non-discrimination requirements • support for tiered or differentiated pricing approaches **Non-discrimination (clause 6B.21)** We support the intent of preventing ownership-based discrimination. However, clarification is required to ensure legacy arrangements, established under different regulatory frameworks do not create unintended constraints or expectations of consistency. We recommend clarifying that differences in charges do not constitute discrimination where they arise from: • timing of arrangements, or • the regulatory framework applying at the time charges were set. This would preserve the intent of the provision while supporting practical implementation and transition.