IEGA
INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

[redacted]

3 June 2026

Network Pricing Team
Electricity Authority
P O Box 10041
Wellington 6143

By email: distribution.pricing@ea.govt.nz

Dear Janet and team,

Re: CROSS SUBMISSION - Consultation Paper - distribution injection pricing

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to make this cross submission on the Electricity Authority's (Authority) proposals to reform network pricing for distributed generation with the objective to promote efficient investment.[1] A cross-submission process on this topic is welcomed – especially given the high level of interest demonstrated from the 46 submitters.

Key next step

Firstly, the IEGA agrees with the ENA's description of, as well as the value from, the joint work underway to address uncertainty with the current DGPPs and the proposed incremental pricing principle though industry-developed guidance.[2] This important work is also highlighted by other submitters.[3] For example, Counties submitted "*industry developed guidance is the most appropriate way to address any residual uncertainty in application of the current and/or proposed DG pricing rules*".[4]

Vector submitted that a collaborative process to develop guidance before Code changes are put in place "*will allow the sector to work through practical examples, uncover unintended consequences, assess the system changes and agree on realistic implementation timelines. This will avoid mid-stream changes to guidance that may materially change implementation approaches and will result in a better implementation process for all parties*."[5]

---

[1] A Committee of the IEGA has signed off this submission on behalf of members.
[2] ENA submission, section 2.1
[3] For example: Counties submission page 3 and answer to Q14; Orion submission pages 2 and 4 and answers to Q2 and Q14; Alpine page 2 and answer to Q6 and EA Networks Q14 refer to industry collaboration more generally
[4] Counties submission page 3
[5] Vector submission pages 1-2

Orion highlights the value of having a range of expertise in the discussion on interpretation and guidance: "*Orion supports this being developed by the ENA, IEGA and other stakeholders, including experts who have both an understanding of pricing as well as the practical mechanics of connecting and supplying electricity.*" "*This will ensure definitions are both effective and workable*."[6]

Counties submitted "*we still consider that there is residual uncertainty in what costs may be 'reasonably charged'. Further guidance, preferably codeveloped by industry, to provide greater clarity would highly benefit the sector*."[7] The IEGA agrees with Alpine (and others) requesting clarity that the incremental cost principle applies to the initial up-front directly attributable connection charge and any costs attributable to dg that are recovered on an annual basis.[8]

Numerous submitters seek clear guidance, transparent methodologies and consistency across distributors which will be enabled by collaboratively developed guidance and worked examples.[9] The IEGA agrees with Vector's conclusion that "*The transparent methodologies, worked examples and stable guidance provide DG investors with confidence that the 'reasonable estimate' is evidence based and defendable*.[10]

The remainder of this cross-submission focuses on:

a) The case for considering 'load-related DG' and 'stand-alone DG' separately
b) The interrelationships of distributed generation with the evolving power system and management of network capacity
c) Detailed suggestions about the type of monitoring the Authority should undertake
d) Support for voluntary (rather than mandatory) establishment of pioneer schemes for related to stand-alone DG connection assets
e) Retrospective application of charges
f) Broadening the scope of non-discrimination clause
g) Reconsider implementation timeline

a) The case for considering 'load-related DG' and 'stand-alone DG' separately

The IEGA agrees with Rethink Energy that the Authority should acknowledge the distinction between load-related DG and stand-alone DG:

"When considering policy relating to DG the EA may find it helpful to acknowledge a distinction between DG that is fundamentally load-related and DG that is stand-alone.

Load-related DG *is primarily for the purpose of serving co-located load, with the injection capability being ancillary to this primary purpose. Rooftop solar PV is the classic example, but stationery or vehicle-to-grid battery storage will also become increasingly prevalent. It is reasonable for mass market electricity consumers to expect to host these types of distributed energy resources with*

[6] Orion submission answer to Q14 and Q2
[7] Counties submission answer to Q7
[8] Alpine submission answer to Q30
[9] For example, Vector submission answer to Q3 and Q30
[10] Vector submission answer to Q7

reasonable opportunity to inject surplus to the public network regardless of where they live or do business. Our community might expect that the associated costs and benefits are reasonably consistent across installations with similar technical attributes in similar locations, regardless of who was first or last.

Stand-alone DG *is primarily for the business of injecting energy to the public network. The technology, location, and size are selected by a developer to optimise the economics of electricity generation or storage. There is not the same moral compulsion to ensure that every location can support this kind of injection or that costs are consistent between projects. Socialisation of costs is less appropriate, sharp and predictable economic incentives are important, connections are typically governed by contracts setting out explicit long-term expectations, and it is accepted that developers are competing and that there will be winners and losers."*[11]

In our view, and as discussed in the IEGA submission, framing the problem definition and analysing the impacts of the current DGPPs would be easier if the Authority took this approach. This could enable evidence-based analysis and conclusions as opposed to assertions as referred to by SEANZ submission response to Q3.

The IEGA also agrees with Rethink Energy that "*it is helpful to acknowledge that distribution networks exist fundamentally for the purpose of serving offtake. This is different from transmission, which has the fundamental purpose of connecting injection and offtake. In a hypothetical system that started with only large high-voltage transmission-connected loads and generators, it is hard to imagine the advent of solar PV or other modular generation technologies giving rise to a distribution network. In other words, DG is by nature an opportunistic augmentation of distribution systems, not their reason for being*."[12]

Westpower ask that the Authority continue to consider how: • resilience, • outage mitigation, and • local flexibility services are valued within pricing frameworks, particularly for isolated or high-risk regions. The IEGA suggests this analysis would be easier if each of load-related DG and stand-alone DG were considered separately.[13]

IEGA's submission highlighted that directly attributable incremental costs for generation-only sites can be more specifically identified. This was emphasised in Lodestone's submission. We agree with Wellington Electricity that "*The standard should support robust and transparent estimation, not impose an expectation that every cost driver can be calculated with engineering-level precision for every individual connection*."[14]

Powerco also submitted that "*Regulation must be proportionate and consistent Transaction and search costs are proportionately much higher for smaller customers. Heavy regulatory intervention, complex bespoke pricing, and pioneer schemes should be reserved for the largest customers to avoid unnecessary administrative burdens that ultimately come at a cost to all consumers."*[15]

[11] Rethink Energy submission page 1
[12] Rethink Energy submission answer to Q5
[13] Westpower submission answer to Q22
[14] Wellington Electricity submission page 3
[15] Powerco submission page 1

While the Authority's Q17 is about bespoke arrangements for capacity charges for larger distributed generation, the IEGA suggests Vector's response to this question is equally applicable to all / any charges for stand-alone DG:

"Yes, larger connections are more complex and should be managed through a more bespoke framework that recognises dependability, controllability, operating envelopes, and the risk of over-compensation. In Vector's view, such an approach should look like: charges and rebates based on agreed service characteristics rather than broad averages, explicit recognition of controllability and dependability, agreed operating envelopes or other technical limits where appropriate, and protections against over-compensation where a party is already receiving value through avoided network charges, export rewards, flexible connection discounts, operating envelope arrangements, or separate flexibility payments."[16]

b) The interrelationships of distributed generation with the evolving power system and management of network capacity

The IEGA agrees with submitters who highlighted the distributed generation pricing principles are one component of a wider environment that can influence efficient generation investment decisions and network planning/investment.

Wellington Electricity group together DG with other relevant investments that impact distribution network usage and investment and planning: "*The expected growth in distributed generation, batteries, electrification, and more active customer participation means that pricing rules need to be clearer, more durable, and better aligned with efficient long-term network outcomes*."[17]

"*Vector considers reform of the distributed generation pricing principles (DGPPs) to be part of the broader evolution toward price-led coordination of two-way distribution networks. Efficient injection pricing is not simply a cost-recovery issue. It is also a coordination mechanism that can reveal where injection imposes costs, where it provides network benefits, and where operating envelopes, flexible connection terms or targeted flexibility arrangements may be required. This framing is consistent with the Authority's statutory objective of promoting efficient investment in generation, batteries and network capacity*."[18]

ENA also discuss this in their submission - see section on 'Evolution of congestion and other polices':[19]

" … EDBs are deploying non-traditional tools such as curtailment schemes, active network management, dynamic operating envelopes, and flexibility procurement to manage constraints and maximise utilisation of existing assets. At the same time, related policy development is ongoing, including flexibility service market frameworks, congestion pricing and access arrangements, and transmission pricing reform.

If the DGPPs are amended ahead of clarity on these interacting policy settings, there is a risk of unintended consequences. In particular, pricing signals for load, generation, and flexibility services may

[16] Vector submission answer to Q17
[17] Wellington Electricity submission page 1
[18] Vector submission page 1
[19] ENA submission page 7

become misaligned; congestion management costs and benefits may be allocated inefficiently; and short-term pricing responses may lock in investment or operational behaviours that become inefficient as congestion frameworks mature. This risk is heightened because congestion outcomes are increasingly driven by time- and location-specific operational constraints, while DGPPs remain largely static and connection-focused."

As Orion notes: "*Capacity pricing is complex and needs to be able to adapt overtime*."[20] Jesse Card's submission states "*there is also a risk that broadening the interpretation of incremental costs too early may lead to cost allocation that reflects anticipated future constraints rather than current conditions*" and suggests trigger conditions for introducing charges.

Powerco also highlights "*Injection and offtake capacity are not coincident - when a network is congested for offtake then any injection will relieve that congestion and vice-versa*."[21]

EA Networks notes it "*is experiencing injection congestion, and is currently issuing application approvals that include restrictions on output. Under the current framework, injecting customers have the option to fund additional capacity, or avoid using the network when it is constrained (through participating in a congestion management scheme). This approach encourages efficient use of the hosting capacity. Moving to a congestion charge approach to manage constrains is a very significant change, and provides a much less certain outcome. To ensure that the stability of the network is not compromised, it will need to be backed up with a congestion policy that mandates curtailment. … We do not think that robust solutions can be developed and implemented in the timeframes the Authority is proposing*."[22]

Counties point out that the preferred capacity pricing could depend "clarity on the types of costs that can be reasonably attributed to DG under the new DGPPs has been established"23

Submitters support collaborative work by the ENA and IEGA on a non-prescriptive approach to capacity pricing. For example, "*Waipā Networks supports a non-prescriptive approach to capacity pricing as networks face different constraints and require flexibility, supported by guidance*"[24] "*We believe however that guidance should be provided to assist distributors and promote consistency of approach where appropriate.*"[25]

Vector submitted the "*most useful guidance would be on capacity-cost allocation methods, congestion charging, large/hybrid worked examples, and how to reflect controllability and dependability without double counting. Specific guidance that would be useful here would include: worked examples for larger injection and hybrid connections, how to treat controllable versus non-controllable injection, how to deal with over-injection and dependence on operating envelopes, and how to structure reconciliation so capacity charges can be traced and audited*" and how to avoid double-counting.[26]

[20] Orion submission answer to Q8
[21] Powerco submission answer to Q30
[22] EA Networks submission answer to Q13
[23] Counties submission answer to Q8
[24] Waipā Networks submission answer to Q8
[25] Waipā Networks submission answer to Q16
[26] Vector submission answer to Q18

Vector describes the benefits of guidance in relation to capacity as: Both parties will understand the connection charges reflect real costs and benefits "*provided the guidance is clear on how distributors may: recover ongoing incremental costs associated with injection; reward injection where it reduces network costs or frees up offtake capacity; apply capacity and congestion pricing where export capacity is scarce; and avoid double counting where the same behaviour is already incentivised through another price signal, flexible access arrangement or flexibility payment*."[27]

Other requests relating to the content of guidance include:

- Westpower: "*Simple capacity-based approaches suitable for rural networks; • When congestion pricing is likely to be efficient versus alternative tools; • How to phase approaches as network conditions evolve*"[28]
- Waipa: "*guidance would be helpful on congestion pricing, capacity allocation and tariff design*"[29]
- Alpine: "*guidance on how to calculate injection capacity costs, how capacity charge revenues should be returned, rebated, or offset, and how capacity charges should be coordinated with congestion pricing would support consistent and efficient application of the new rules"[30]*
- Powerco: "*In our answer to question 2 we suggest specific guidance on the use of auction-based mechanisms or other commercial mechanisms for allocating capacity, to achieve the incremental cost principle, would be helpful in EDBs better understanding the use of novel pricing approaches. Similarly, it would be helpful for the Authority's DGPP reforms to clarify how, and if, export price signals should be used to provide an incentive for customers (or their agents) to self-curtail on-site generation export and increase load (including BESS charging) in export constrained locations*"[31]

c) Detailed suggestions about the type of monitoring the Authority should undertake

There are numerous suggestions about the type of monitoring the Authority should undertake – not just monitoring compliance with the Code.

The IEGA supports the focus suggested by some submitters[32] about the details the Authority should monitor:

- whether distributors recognise benefits as well as costs
- whether methodologies are consistently applied
- whether small participants can understand and respond to pricing signals
- whether pricing supports electrification and distributed participation
- monitoring should include evidence on whether useful injection is being fairly rewarded, whether low-value injection is treated through low or nearzero payment rather than charges merely for supplying electricity, whether flexible demand is being enabled to absorb excess generation, whether claimed network constraints reflect genuine efficient cost rather than

[27] Vector submission answer to Q7
[28] Westpower submission answer to Q18
[29] *Waipā* Networks submission answer to Q18
[30] Alpine submission answer to Q18
[31] Powerco submission answer to Q18
[32] Imported Vehicle Industry Association submission answer to Q15; Christian Alexnder submission answer to Q15

avoidable underinvestment or weak planning, and whether nonincumbent participants receive equivalent treatment where they provide equivalent system value

- whether "system value" is being assessed by reference to consumer benefit and efficient system operation, rather than distributor revenue protection, incumbent generator profitability, or preservation of existing market structures.
- actual outcomes, not only formal compliance. The Authority should monitor: 1. Whether distributors publish clear injection-pricing methodologies. 2. Whether methodologies explain both costs and benefits. 3. Whether applicants receive enough information to assess the reasonableness of incremental-cost charges. 4. Whether benefit recognition becomes more common where justified. 5. Whether pioneer schemes are used. 6. Whether connection projects still stall or withdraw because of shared upgrade costs. 7. Whether independent and affiliated projects receive comparable treatment. 8. Whether disputes increase or decrease. 9. Whether methodology quality improves over time.10. Whether common or low-risk connection types are able to proceed through proportionate standardised pathways. 11. Whether applicants report improved ability to understand and test incremental-cost explanations. 12. Whether monitoring identifies any need for further guidance on storage, flexible export, aggregated DER or VPP arrangements.
- Monitoring should also test whether the framework is becoming too complex. A pricing reform can fail not only by under-allocating costs or ignoring benefits, but also by creating methodologies so granular that smaller applicants, retailers or consumers cannot understand the basis for charges. The Authority should therefore monitor usability and predictability as well as formal cost-reflectivity.

d) Support for voluntary (rather than mandatory) establishment of pioneer schemes related to stand-alone DG connection assets

The IEGA and numerous submitters agree that the establishment of pioneer schemes related to stand-alone DG connection assets should be voluntary. [33]

The IEGA supports the ENA's feedback that "*There are limited circumstances in which pioneer schemes are likely to be beneficial for injection connections compared with offtake connections, and the administrative burden associated with these schemes is significant. Due to investment efficiency, distributed generation will typically build solutions that utilise all economically available capacity. This is different to most load customers that may consider location to reduce costs but typically determine load capacity based on other drivers*."[34]

The Imported Motor Vehicle Industry Association submission describes criteria for when a pioneer scheme is relevant: "*If a network upgrade is private or dedicated to one connection, it can properly be charged to the connecting party. If an upgrade creates shared network capacity for later households, SMEs, community schemes, batteries, EV chargers, generators, or other users, it should be treated as shared infrastructure. If it is a general network-readiness upgrade required for foreseeable electrification and distributed participation, it should be planned and funded as part of the network's*

[33] Including Westpower, Wellington Electricity, Vector, Network Waitaki, Alpine EA Networks, Orion Powerco, ENA

[34] ENA submission section 4.1

transition, not loaded onto the first participant who happens to expose the constraint. Pioneer schemes should therefore cover injection capacity only where they prevent one participant from bearing shared costs that later users should fairly share."[35] [emphasis added]

Vector notes that "*Capacity pricing, localised cost recovery mechanisms, congestion pricing and flexible access arrangements may in some cases provide simpler or more efficient solutions*" than pioneer schemes.[36]

e) Retrospective application of charges

The IEGA supports the ENA's and distributors perspective for not supporting retrospective application of any new pricing principles: "*ENA does not support the mandatory application of the updated injection pricing principles to lines charges for existing injection customers. Revisiting contracts in a relatively short period—some negotiations have been lengthy and detailed—would be administratively burdensome and inefficient, could undermine investment incentives that have already been agreed and if performed without sufficient consideration, increases an EDBs risk of a Code breach*"[37]

Lodestone provides a distributed generator perspective: "*On retrospectivity, existing DG projects require certainty. Retrospective changes to charges that alter the economics of consented or financed projects would be deeply damaging and should be avoided. Where new pricing rules result in increased charges, these should apply only to new connections or at the next scheduled pricing reset for existing connections, with adequate notice*."[38]

Genesis is also concerned "*with the proposal retroactively applying new lines charges to existing injection connections, and we are unclear on the impact and materiality this would be likely to have. Predictability of network pricing is fundamental to investment confidence. This would create significant complexity - existing projects and business cases are based on current distribution charges. Any changes to these would create workability issues and investment risk for producers*."[39]

f) Broadening the scope of the non-discrimination clause

The IEGA supports submitters[40] that agreed with inclusion of a non-discrimination clause. However, the breadth of the clause should be reconsidered. It should not only be when determining charges/prices but also other technical discretionary aspects (such as export capacity) where distributors should be required to apply a non-discriminatory approach.

---

[35] Imported Motor Vehicle Industry Association submission answer to Q12
[36] Vector submission answer to Q29
[37] ENA submission section 6.2
[38] Lodestone submission answer to Q12
[39] Genesis Energy submission answer to Q12
[40] Including Westpower, SEANZ, Waipa Networks, Vector, Top Energy, Alpine, Counties Orion, Lodestone

The Imported Motor Vehicle Industry Association submitted "*Non-discrimination should not be merely formal. It should be supported by usable methodology disclosures, monitoring, and the ability for affected parties to identify and challenge inconsistent treatment*."[41]

Another submitter suggested the Authority "*should monitor whether comparable independent and distributor-affiliated projects receive comparable treatment in: 1. Methodology assumptions. 2. Timing. 3. Access to capacity information. 4. Pioneer scheme treatment. 5. Charges or rebates. 6. Dispute outcomes. 7. Bespoke arrangements*."[42]

Lodestone submitted the opt-out clause should not be able to be used by distributors for their own generation investment – this could be an avenue for discrimination.[43]

g) Reconsider implementation timeline

The IEGA agrees with the ENA and other submitters[44] that the Authority should reconsider the implementation timeline. The ENA and many distributors have described the practical difficulties with the Authority's proposed timeline creating risks for both distributors and generation investors and the potential for unintended consequences.

As discussed above a number of submitters request clear information prior to the effective date of any proposed changes. This is described well by the Imported Motor Vehicle Industry Association: "*Implementation should include plain language guidance, worked examples, standardised disclosure templates, accessible explanations for households and SMEs, and machine-readable price and tariff data. Methodologies should be practically usable, not merely published. <u>Guidance should explain the distinction between private generation assets, dedicated connection assets, shared network infrastructure, and any explicit support mechanisms for generation, storage, or flexibility</u>. It should also explain how system value is assessed by reference to efficient system operation and long-term consumer benefit, and how low-value injection is treated without becoming a punitive charge on generators*"[45] [emphasis added]

Alpine Energy "*recommends supporting implementation through: Clear, practical worked examples for small, medium, and large injection connections Early guidance on how capacity pricing and congestion charging are expected to work; Sectorwide information sharing through ENA, so new DGPP rules are applied consistently, and effort is not duplicated across the sector; Alignment between EA requirements and ID pricing methodology requirements …* "[46]

[41] Imported Motor Vehicle Industry Association submission section 7
[42] Christian Alexander submission answer to Q12
[43] Lodestone submission answer to Q12
[44] Including Westpower, Waipa Networks, Vector, Alpine, Counties, EA Networks, Orion
[45] Imported Motor Vehicle Industry Association submission answer to Q14
[46] Alpine submission answer to Q14

Concluding remarks

At this stage in NZ's drive to commission more renewable generation capacity it would be counterproductive for the Authority to implement any changes that create more uncertainty, ambiguity and complexity for generation investors.

The IEGA agrees with Vector's view that "*the objective [of these proposals] should not just be to improve cost allocation in theory, but to do so in a way that remains workable, transparent, and aligned with how transmission and distribution pricing operate together*".[47]

The IEGA supports Powerco's submission that the Authority should "*Reconsider if the proposals have addressed the primary problems the Authority has identified are inconsistent interpretation of the incremental cost rule across EDBs and the position in queue hold ups*".[48]

The IEGA plans to continue collaborative work to improve the understanding and application of the current DGPPs. If the Authority decides to progress changes to the DGPPs, the IEGA submits there is industry support for collaboratively developed guidance to be available before the effective date (or even finalisation of the Code).

We would appreciate the opportunity to discuss this formal submission with you as well.

Yours sincerely

[redacted]

Ben Gibson
Chair

[47] Vector submission answer to Q24
[48] Powerco submission answer to Q24