Submission: Reforming distributed generation pricing to promote efficient investment

To: distribution.pricing@ea.govt.nz

From: Duane Fernandes (personal capacity)

Date: May 2026

Re: Consultation paper *"Reforming network pricing for distributed generation to promote efficient investment"*, due 5pm 19 May 2026

Cover note

The EA should adopt the four proposed amendments, and use the decision paper to nominate where the next-cycle work on the bidirectional, citizen-aggregated regulatory unit will land inside the EA's existing programme — specifically the Energy Competition Task Force and the Pricing in a Renewables-Based Electricity System workstream.

The four amendments are directionally correct. They fix specific, known distortions in how lines companies allocate costs and benefits to distributed generators, and they remove an incremental-cost test that has become unworkable. I support all of them.

They are also one regulatory cycle late.

The DGPPs price an injection connection inside a regulatory frame written for one-way networks. The architecture households, businesses and lines companies will be operating in by 2028 is not one-way. Three things have happened in parallel.

- **The unit of value is shifting from exported electrons to onsite consumption.** PulteGroup, Nvidia and Span shipped a residential data-centre architecture in May 2026 that consumes rooftop surplus on the side of the house and sells the digital output (training, transcoding, inference) into a global compute market. The buyback rate stops mattering. The DG injection price stops being the binding economic question for those households (CNBC, 5 May 2026).
- **The actor doing the generating is changing.** The 2010 DGPPs anticipated DG as a small set of industrial-scale injection connections. The marginal injection connection in 2027 is a 7kW residential rooftop with a battery and an EV. NZ has 855 MW of distributed solar installed and growing on a roughly 24-month doubling cycle, 450 MW of technically available demand-side flexibility, 135,348 EVs in the fleet, and battery installation growth that accelerated by 72% in the year following the July 2024 tariff rebate decision (EA EMI; EA *Promoting demand flexibility* paper 2024; MoT EV statistics).

- **The coordination layer is being designed somewhere right now.** If NZ doesn't write rules that recognise third-party aggregators, neighbourhood-level pooling, and onsite consumption as legitimate first-class market actors, the dominant gentailers and the larger distributors will set the terms by default. The DGPP reform fixes price fairness inside that architecture without questioning whether it is the right architecture. Australia's AEMC has rules enabling peer-to-peer energy trading and DER aggregation (AEMC P2P Rule 2021; DER Integration Final Report 2023). NZ does not.

The ask is simple. Adopt the four proposed amendments. Use the decision paper to nominate where the next-cycle work lands. The Energy Competition Task Force is the natural home for the aggregator, third-party retail, and household-as-market-actor questions (and its 2026 refreshed priorities already cover demand-side flexibility and DER coordination). The Pricing in a Renewables-Based Electricity System workstream — the MDAG follow-up — is the natural home for the question of how wholesale price signals reach households directly. The Multiple Trading Relationships trial is the right vehicle to extend for onsite consumption. None of this requires standing up a new workstream. It requires naming, in this decision paper, which of the existing ones picks up which piece, and by when. The window to influence that architecture is open right now and closes inside 18 months.

The rest of this submission answers the questions in Appendix J that I have a substantive position on. I have not answered every question; the technical-drafting and process-compliance items I have left to participants better placed to comment.

Responses to consultation questions

Q1. Background and context

The background is accurate as far as it goes. The diagnosis of cost under-allocation, definitional fragility around incremental cost, and the position-in-queue distortion is correct, and the consumer-impact analysis (Appendix A, as corrected on 21 April) is honest about its assumptions.

What the background omits, and should not, is the change in the underlying unit of distributed generation since the original DGPPs were written. By 2026, three structural shifts have occurred:

1. **DG is now predominantly residential and small-commercial, not industrial.** The bulk of the 855 MW of installed distributed solar in NZ is on rooftops, not in commercial-scale arrays. Growth doubles roughly every 24 months.
2. **The same household assets are simultaneously load and generation.** A house with rooftop solar, a battery, an EV, a heat pump hot water cylinder and (increasingly) onsite compute load is bidirectional in real time. The DGPPs treat the injection connection and the load connection as separate regulatory units. For a growing share of the network they are the same physical connection point operated by the same

actor. Pricing reform that treats them separately is reforming a category that is dissolving.

3. **The economic value of an exported electron is being overtaken by the value of the same electron consumed onsite for a tradeable digital output.** AWS H100 spot prices fell ~88% in 2025 (industry trackers). Akash, Vast, RunPod and Hyperbolic run production GPU spot markets today. Revenue per kWh consumed in onsite compute runs 10-15x revenue per kWh exported at any current NZ buyback rate.

These shifts don't invalidate the four proposed amendments. They do mean the EA should be explicit that this DGPP reform is a fix on the export-pricing axis of a problem that is becoming bidirectional.

Q2. Workability of the incremental-cost rule

Yes. The "must not exceed incremental cost" formulation imports a precision that does not exist in the underlying engineering and forecasting. Incremental cost depends on which network upgrade is counterfactual, over what horizon, and against what load and injection scenario. None of those inputs are knowable to the precision the rule implies. The observed industry response — under-allocation to avoid breach risk — is a rational response to a rule that punishes estimation error in only one direction.

The challenges already discussed are the right ones. One additional challenge: the current rule disadvantages distributors that genuinely try to estimate incremental cost over those that under-allocate by default, because the former carry the breach risk while the latter do not. The reframe in Q6 corrects that asymmetry.

Q3. Under-allocation of costs and benefits

Yes. The current DGPPs systematically under-allocate both costs and benefits to injection connections. That is the natural consequence of a "must not exceed" rule combined with weak benefit-recognition obligations. The result is a settlement that neither costs nor rewards DG appropriately, which sends muted price signals in both directions.

The substantive harm is real but asymmetric across DG types. Industrial-scale DG with strong network benefits (transmission deferral, voltage support at the periphery) is under-rewarded. Residential and small-commercial DG that creates local network costs (back-feed, voltage rise, congestion at the LV transformer) is under-charged. Both errors point in the direction of distorted investment relative to a cost-reflective benchmark.

Q4. Should injection pricing methodologies remain regulated?

Yes. The asymmetry of bargaining power between an individual injection connection (especially residential and small commercial) and a regional distributor is structural. Removing the methodology requirement would not produce a competitive outcome; it would produce price discrimination by default.

The harder question is granularity, not whether to regulate. The current regime regulates the methodology and lets distributors implement. As the injection-connection population shifts to hundreds of thousands of small actors, the methodology needs to be specified more tightly than the current framework allows, or distributors will have effective discretion over a price that materially affects 100,000+ households.

Q5. Should consumers remain residual payers?

Yes, with one caveat the current framing misses.

The residual-payer principle is appropriate when the boundary between "consumer" and "distributed generator" is meaningful. The consumer-impact analysis is built on that boundary. As the household-as-bidirectional-actor becomes the dominant case, the boundary loses analytical content. The same household pays residual costs as a consumer in winter mornings and is the marginal injection in summer afternoons.

The pricing principles need to anticipate this. Any methodology that recovers residual costs from "consumers" should be tested against the case of a household with rooftop solar, battery, EV and dispatchable load whose net role on the network varies by time of day. The current consumer-impact methodology, which separates "small DG owners" from "consumers without DG", will become a less useful frame as that separation dissolves.

An additional economic concept that should sit alongside cost-recovery: the social value of bidirectional flexibility should be priced as a benefit to the system, not just as a cost-recovery question. The current DGPPs reward DG for "benefits brought to the network" in narrow terms (avoided losses, deferred upgrades). The full benefit set in a bidirectional world includes voltage support, local balancing, congestion management and (where the broader regulatory framework allows) participation in wholesale and reserves markets. Reframing benefits in those terms is consistent with the EA's statutory objective and the long-term consumer interest.

Q6. Reframing the incremental-cost rule

Yes. Moving from "must not exceed" to "must reflect a reasonable estimate of" is the right move. The current rule is unworkable because incremental cost is not knowable with the precision the rule implies, and the workaround has been to under-allocate to avoid breach risk. The reframe is honest about the underlying uncertainty and consistent with how cost allocation works on the load side.

One drafting point: "reasonable estimate" should be paired with an obligation to publish methodology and assumptions, so distributors are accountable for the estimate even if not for its precision. Without that, the change increases distributor discretion without a corresponding accountability mechanism.

Q9-Q10. Pioneer schemes for injection connections

Yes to both. Extending the pioneer scheme to injection connections is necessary to address the position-in-queue distortion. The current rule, where the marginal injection connection that triggers a network upgrade pays the full cost of that upgrade alone, is the most direct DG-deterring distortion in the current code.

Pioneer schemes should also cover network injection capacity, not just connection. The capacity headroom on a feeder is a shared resource. Treating its allocation as a first-come-first-served lottery with the loser paying for everyone else is economically arbitrary and disproportionately penalises smaller and citizen-led DG projects that cannot time the queue against utility-scale developers.

Q11. Non-discriminatory pricing requirements

Yes. The proposed non-discrimination provisions are necessary, particularly given the trend toward distributors investing in their own DG (the 2025 ENA papers on lines-company-owned grid-edge storage are the clearest signal). The structural conflict — a distributor pricing third-party injection connections while running its own competing assets — is one the regulatory framework should resolve, not leave to good faith.

The EA should monitor discriminatory-pricing risk specifically for community-owned and citizen-aggregated DG. These actors have the least capacity to mount a regulatory challenge and the most to lose if pricing favours the distributor's own injection connections at the margin.

Q19-Q21. Transmission connection charges and benefit recognition

Yes, the inconsistent treatment is distorting investment. Yes, the restriction on recognising transmission benefits should be reconsidered as part of the same package.

The current treatment has two related effects. First, it undercharges transmission-connected generation for the local network costs it imposes when its connection requires distribution-level reinforcement. Second, it under-rewards distribution-connected generation for the transmission-system benefits it delivers (deferral of grid upgrades, peripheral voltage support, reduction in transmission losses at peak). The combined effect is to bias investment toward transmission-connected generation in cases where the system-wide cost-benefit analysis does not support that bias.

On Q20, the preferred option is reform that aligns the cost-allocation principles for transmission and distribution connections, applied symmetrically. A piecemeal fix to one side without the other leaves a residual distortion that will surface in DG investment decisions. The principle should be: where DG delivers a transmission-system benefit that defers, displaces or reduces transmission cost, that benefit should be recognised in the DG's network charge using the same methodology framework that applies to distribution-level benefits. Different methodologies are acceptable; different principles are not.

On Q21, the restriction on recognising transmission benefits made sense when the DGPPs were drafted in an environment where DG was small enough that transmission benefits were a rounding error. That environment no longer exists. Distributed generation is now a meaningful share of system capacity, and its transmission impact (positive at the periphery, congesting at the GXP in some cases) is no longer immaterial. The restriction should be removed, and the methodology framework extended to recognise transmission benefits where they exist and are quantifiable.

Q22. Other matters — the parallel workstream

This is the question on which I want to spend the most space.

The DGPP reform is necessary and the four amendments should proceed. The EA should use the decision paper following this consultation to nominate, by name, the existing workstreams that will pick up the next-cycle questions, and the timeline for doing so. Four items, four homes.

1. Recognise onsite compute consumption (and dispatchable digital-output loads more broadly) as a legitimate household economic activity. A household running a coordinated GPU load on its own electrons is producing tradeable output. The treatment of that revenue, the metering protocols, and the relationship to the retail tariff need their own regulatory unit. Treating this as "consumption with extra steps" hands the value spread to the incumbent retailer by default. *Home: Multiple Trading Relationships trial (Sapere/EA, January 2026), extended in scope.*

2. Unbundle a household's right to consume its own electrons from the gentailer retail relationship. The retailer currently controls the relationship between the household and the wholesale market. In a compute-VPP and household-flexibility world, the household needs direct exposure to wholesale price signals (or a genuine third-party aggregator) to convert price signals into onsite economic decisions. The retailer is one possible aggregator, one of several legitimate options. The current code does not enable the others. *Home: Energy Competition Task Force, building on the 2026 refreshed priorities on flexibility services and DER coordination; with the wholesale price-signal reach question picked up by the Pricing in a Renewables-Based Electricity System workstream (MDAG follow-up).*

3. Enable neighbourhood-level aggregation as a first-class market actor. Fifty households should be able to pool into a single VPP node that transacts with the grid operator, the distributor, and external markets without going through an incumbent retailer and without needing hyperscaler-scale infrastructure. The AEMC's peer-to-peer rule (2021) and DER integration framework (2023) are workable precedents. *Home: Energy Competition Task Force, alongside the existing "new ways to empower electricity consumers" workstream.*

4. Treat citizen co-ops, energy trusts and community schemes as recognised market actors in the DGPPs. Germany's Energiewende was built on roughly 950 energy cooperatives with around 220,000 members, and the cooperative structure remains the dominant model for new community-led generation in the EU (DGRV / Bürgerenergie reporting, 2024). Denmark's 59% wind-generation share rests on a wind fleet that is approximately half citizen-owned (Danish Energy Agency, 2024). The DGPPs as drafted treat the injection connection as a counterparty without distinguishing the actor behind it. Pricing rules that recognise community schemes as a distinct category — with associated rights including pooled connection assessment and shared-asset capacity allocation — would unlock a class of investment that current rules effectively suppress. *Home: the next stage of distribution pricing reform flagged in this consultation paper, with the actor-recognition piece picked up by the Energy Competition Task Force.*

These four items are not in scope for the current consultation. They should be in scope for the next stage of each named workstream, and the EA should say so in the decision paper that follows this consultation. Naming the homes matters: it removes the option of treating each item as somebody else's problem, and it gives industry, community groups and consumer advocates a specific consultation surface to engage with.

A point on sequencing: if the EA delivers the four DGPP amendments in 2026 and does not signal where the next-cycle work lands until 2028, the gap will be filled by incumbents writing the architecture inside their commercial relationships. That architecture will then be very difficult to reverse through regulation.

Q28. Consistency with the distribution pricing principles and section 15 of the Act

The high-level settings are consistent with the distribution pricing principles in the narrow sense. They remove distortions and improve cost-reflectivity inside the existing pricing architecture. Whether they are consistent with section 15 of the Electricity Industry Act 2010 — the long-term benefit of consumers — depends on what "long term" is taken to mean.

If "long term" is interpreted as the next pricing cycle inside the current architecture, the proposed amendments meet the test. They remove specific distortions, improve allocative efficiency, and reduce barriers to DG connection.

If "long term" is interpreted to include the architectural shift that the next 5-10 years will produce — bidirectional household actors, third-party aggregation, onsite consumption of generated electrons for tradeable output — the proposed amendments do not meet the test on their own. They price an injection connection inside a frame that is being overtaken by a bidirectional, citizen-aggregated unit, and they make no provision for that transition.

This is the most important interpretive question in the consultation. The EA should be explicit about which interpretation is operative. My reading of the consultation paper is the first interpretation: the DGPP reform is a fix on the export-pricing axis pending broader reform. If that is correct, the decision paper should say so, and should name the existing workstreams that pick up the broader reform — the Energy Competition Task Force for the aggregator and household-as-actor questions, Pricing in a Renewables-Based Electricity System for wholesale price-signal reach, and the next stage of distribution pricing reform for the bidirectional pricing-unit question — together with a published timeline. If the EA intends the second interpretation — that this is its full statement on DG pricing for the medium term — then the long-term consumer interest test is not met, and the consultation paper should be amended to address that.

The choice between those two interpretations is the substantive decision the EA is making with this consultation. It should be made explicitly, not by default.

Closing

The DG injection price has been the visible argument in NZ residential energy economics for two decades. It will be a footnote inside ten years.

The architecture that replaces it is being designed somewhere right now. The household, the grid and the lines network all win when the surplus is consumed onsite, the household is the market actor, and pricing rules recognise that bidirectional reality. They lose when the rules around that surplus are written without them in the room.

The four amendments in this consultation are correct. Adopt them. The decision paper that follows should do one more thing: nominate, by name, the existing EA workstreams that pick up the regulatory-unit question — the Energy Competition Task Force, the Pricing in a Renewables-Based Electricity System workstream, the Multiple Trading Relationships trial, and the next stage of distribution pricing reform — together with a timeline. The work doesn't need a new home. It needs the existing homes named. The EA's window to set those rules is open. The consultation closing on 19 May is the moment to commit to walking through it.

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Duane Fernandes [redacted] Auckland, May 2026

(Submitted in personal capacity. I run a strategy consultancy advising NZ corporates and family-owned businesses across multiple sectors, including energy. I write publicly on the energy transition. The positions in this submission are mine and not those of any client.)

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