From: Duane Fernandes [redacted]
Sent: Monday, 25 May 2026 8:00 am
To: Distribution Pricing <Distribution.Pricing@ea.govt.nz>
Subject: Re: Distributed generation pricing principles: cross-submission period now open

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Cross-submission: Reforming distributed generation pricing to promote efficient investment

To: distribution.pricing@ea.govt.nz **From:** Duane Fernandes (personal capacity) **Date:** May 2026 **Re:** Cross-submission on the *Reforming network pricing for distributed generation* consultation. Responds to submissions published after the 19 May 2026 close. Due 5pm, 3 June 2026.

Cover note

The submissions converge on more than the four amendments, and the EA should act on the wider convergence: a sizeable, independent cluster of submitters reached the conclusion that this reform is necessary but scoped short. The one submission arguing the EA should instead charge distributed generation more, Entrust, identifies an equity problem the reform agenda has to answer, but prescribes the wrong remedy.

My own submission made two arguments: support the four proposed amendments, and use the decision paper to name where the next-cycle work on the bidirectional, citizen-aggregated regulatory unit lands inside the EA's existing programme. Having read the published submissions, I want to do three things in this cross-submission.

First, show the EA that the "necessary but insufficient" reading is not one consultant's idiosyncrasy. Rewiring Aotearoa, the Imported Motor Vehicle Industry Association, Supa Energy, the consultant Rethink Energy and the individual submitter Graeme Weston each reached it independently, by different routes. Transpower, ERGANZ and Utilities Disputes each named an adjacent workstream without connecting them. Five submitters converging without coordination is a finding, and the EA should record it as one.

Second, support three technical points other submitters made better than I did, and recommend the EA adopt them.

Third, disagree, in the open and with reasons, with the submissions arguing for a narrower or slower reform, principally Entrust on who pays, Contact Energy on transmission benefits, and the near-universal industry call to defer everything to 2028.

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1. The convergence the EA should act on

The four amendments have support that crosses every interest group: lines companies, gentailers, the solar industry, community groups and individuals. That is unusual and the EA should bank it. The direction is not seriously contested: incremental cost as an anchor not a cap, pioneer schemes extended to injection, non-discriminatory pricing, and the transmission connection-charge distortion fixed. The argument is about scope and speed, not direction.

On scope, a second convergence is visible and the EA should not let it pass unrecorded. Read together:

- Rewiring Aotearoa applies section 15 of the Electricity Industry Act as a binding test, and argues, with evidence obtained under the Official Information Act, that the EA has already failed it once, by quietly redefining "mass market" so that medium customers (roughly 45–300kW: farms, marae, small commercial) were excluded from default peak export tariffs without that exclusion being consulted on.

- The Imported Motor Vehicle Industry Association frames households, SMEs, community energy schemes, batteries, aggregators and vehicle-to-grid participants as a single class the Code must be designed to enable, and warns explicitly against entrenching a centralised model while the technology moves the other way.

- Supa Energy describes the same shift as decentralisation and democratisation of supply, and makes the strongest technical case for recognising distribution-level transmission benefits.

- Rethink Energy draws the distinction between "load-related DG" (rooftop solar, batteries, V2G, all ancillary to a household's own load) and "stand-alone DG" (optimised purely for injection), and argues the two are categorically different regulatory objects.

- Graeme Weston builds the end-state in engineering terms: a coordinated network of nodes that optimise internally, dynamic operating envelopes, locational marginal pricing, V2G, the "Energy Internet".

These submitters do not agree on everything. They agree on one thing: the unit the DGPPs price, a one-way injection connection, is being overtaken, and a reform that

does not say so leaves the larger question to be answered by default. That is the argument my submission made. Five other submitters made it without coordination. The EA's decision paper should record the convergence and respond to it, rather than treating scope as closed because the consultation questions were narrow.

The proportions matter here. IEGA's submission quantifies the cost under-allocation this consultation is correcting at roughly $628,000 across its members in FY25, about 29 cents per connection per year. SEANZ puts the average consumer impact at $0.59 a year. Those figures are not an argument against the four amendments; the amendments are about correct price signals, not the size of the sum. They are an argument about proportion. The EA is running a full consultation cycle to reallocate a sub-dollar annual cost, while the question of who captures the value of distributed generation over the next decade has no consultation, no workstream named and no date against it. The decision paper can correct that asymmetry.

The mechanism for responding already exists, and three submitters pointed at pieces of it. Transpower named MDAG Recommendation 5 (price-driven secure distribution dispatch) and the Future System Operator / DSO workstream. ERGANZ named the Government's threshold review, the MDAG programme and the Commerce Commission. Utilities Disputes named the Energy Competition Task Force. Nobody connected them. The decision paper should name the Energy Competition Task Force, the Pricing in a Renewables-Based Electricity System workstream and the Multiple Trading Relationships trial as the homes for the onsite-consumption, aggregation and retailer-unbundling questions, and commit a timeline. It costs nothing and slips no Code drafting.

2. Three points other submitters made better

Lodestone Energy gave the clearest worked explanation in the field of why the distortion at Q19–Q21 matters: a generator connecting directly to the transmission grid pays a share of all existing grid-exit-point assets, while an identical generator embedding in a distribution network pays only its incremental cost. Lodestone also argues, correctly, that the fix belongs at the transmission level, not bolted onto distribution pricing. Its NZ case evidence, including a 37% year-on-year escalation in connection fees at Kaitaia, is the kind of grounded data the EA's own impact analysis lacks. IEGA and Pioneer Energy reinforce the same distortion from the generator side: a transmission-connected generator pays a distributor nothing for the delivery service it relies on, so distribution-connected generation already carries an asymmetric burden. The distortion is documented from both ends.

Orion and SEANZ supplied the evidence behind a point my own submission only asserted, that the household needs a more direct relationship with price signals. Orion's submission shows distribution price signals are routinely "averaged out" inside

retailers' internal pricing before they reach the consumer, so the signal the DGPP reform is calibrating is damped before it lands. SEANZ adds that retailers are not, in practice, passing the new peak export payments through to customers either. This is decisive. A pricing reform whose signal is absorbed by the retail layer is a reform that does not reach the people it is meant to reach. It is direct evidence for why the retailer-household relationship belongs in the next workstream, and the EA should cite it as such.

Moving the incremental-cost rule from "must not exceed" to "must reflect a reasonable estimate of" is the right move. I supported it and the field broadly supports it. But several household submitters (Glass, Gunn, Pustovoi, Oldengarm) read the new discretion as a licence for distributors to over-charge, and that fear is not unreasonable. ERGANZ and Alpine Energy point to the answer: pair the "reasonable estimate" standard with a hard obligation to publish methodology, assumptions and inputs. Discretion with disclosure is accountable. Discretion without disclosure is not. The EA should make published methodology a condition of the reframed rule, not a guidance note.

3. Where I disagree with other submitters

Entrust: right about the problem, wrong about the remedy

Entrust's submission is the most important one to engage, because it argues the opposite of mine from the same starting principle: the long-term interest of consumers. Entrust says rooftop solar sits disproportionately in wealthier households, that reform lowering the network costs borne by distributed generation shifts the residual onto non-solar consumers, and that 91% of residential consumers it surveyed oppose paying more to support businesses.

The first half of that is correct and I should have said so in my own submission. Rooftop solar today is regressive. It requires a roof you own and capital you can deploy. Marlborough Lines and MainPower's submission shows the same pattern in their data, with distributed generation concentrated in higher-socioeconomic suburbs.

The remedy is where Entrust is wrong, on three counts.

First, the remedy Entrust implies, charging distributed generation more until the cross-subsidy closes, suppresses the very thing that defers cost for everyone, including the non-solar household Entrust is protecting. Margarita Parra's submission cites the evidence: distributed generation defers distribution feeder, substation and transmission upgrades (Lawrence Berkeley National Laboratory, 2021), and distributed energy resources coordinated with software can deliver peak capacity at 40–60% of the conventional cost (Pew, 2025). Charge distributed generation off the network and the deferred upgrade comes back onto the bill. The non-solar household pays either way. Entrust's framing counts one side of that ledger.

Second, Entrust's survey finding, that 91% of consumers oppose paying more to "support businesses", rests on a premise its fellow submitters' data does not support. IEGA's submission records that 67% of new distributed generation connections above 10kW are residential or small business. Household solar is not a business. A survey that asks consumers whether they want to subsidise businesses measures the framing, not the question, because the distributed generation actually at issue is mostly other households. That does not dispose of the wealth-concentration concern. The concern is valid, it survives the survey, and it needs an answer.

Third, and most important: the answer to a technology being unevenly distributed is to widen access to it, not to tax the early adopters until adoption stops. Rooftop solar is regressive because it is individual: locked to roof ownership and household capital. Community-owned generation, energy co-operatives, shared neighbourhood assets and third-party aggregators break that lock. They let a renter or a low-income household take part without owning the roof or the battery. Carbon Neutral NZ Trust and the Community Energy Network make versions of this point. Those models are exactly what the current Code does not recognise as market actors, and exactly what the next workstream I am asking the EA to name would address. The equity problem Entrust identifies is not an argument against the reform agenda. It is the strongest argument for finishing it. A DGPP regime that entrenches individual rooftop solar as the only recognised form of distributed generation is itself the regressive outcome. Recognising community and aggregated models is the fix.

Entrust is right that equity belongs in this consultation, and the EA should say so plainly. But the instrument is widening participation, not pricing distributed generation back down.

Contact Energy and the controllability test

Contact Energy proposes that distributed generation should only receive recognition for transmission benefit (avoided cost of transmission) where the benefit is near-term, the generation is controllable, and a payment is required to change behaviour. As criteria for *uncontrolled* generation (a solar panel with no storage and no management), those are defensible. As a gate on the whole category they are self-defeating, because controllability is not a fixed property of distributed generation. It is what storage, smart inverters and aggregation deliver. Apply Contact's criteria as a permanent gate and you decline to reward the controllability you have also declined to build the rules for. The criteria should be read as a roadmap, not a reason to withhold recognition indefinitely: they describe what distributed generation must become to earn full benefit recognition, and they point to the aggregation framework that gets it there. Contact also argues DGPP and transmission pricing reform must move together. Coordination, yes. Using coordination as a reason to defer the distribution-side decision already in front of the EA, no.

Meridian and the transmission-benefit restriction

Meridian opposes reconsidering the restriction on recognising transmission benefits in injection pricing (Q21). ERGANZ raises the substantive reason why: a transmission benefit may already be captured in nodal price signals, and recognising it again in the network charge double-counts it. That concern is legitimate, and my own submission did not address it. But it argues for a bounded fix, not for keeping the restriction. The EA should recognise transmission benefits only to the extent they are not already reflected in nodal prices: net of, not on top of. Supa Energy's submission sets out the same problem from the pricing-theory side: a hybrid of long-run marginal cost pricing at the distribution level and nodal pricing at the transmission level produces a confused signal unless the boundary is drawn deliberately. Draw the boundary. Do not use the existence of the boundary problem as a reason to leave a known distortion in place.

The 2028 timeline and the call to wait

Almost every lines company, with ERGANZ and IEGA, asked for commencement to be deferred to 1 April 2028. David Glass went further and argued the EA should pause and coordinate with the Commerce Commission before changing the Code at all. On implementation timing for the operational changes, the capacity charges and the systems work, the industry's evidence on lead times deserves weight. But two things should not wait for 2028. The EA naming the next workstream is one: it is a paragraph in the decision paper, not a Code change, and it has no implementation cost. Glass's underlying concern is the other: that distributors have a structural incentive to over-capitalise and shift cost into the regulated asset base. It is real, and it is the reason the methodology-disclosure obligation in section 2 should be locked in now, not deferred. The answer to "the reform is hard to implement" is a realistic implementation date. It is not a deferral of the scoping decision.

4. The gap nobody is funded to close

One more point, raised by Utilities Disputes and, in his own way, by the individual submitter Keith Taylor, deserves to be in the decision paper.

Utilities Disputes notes that consumers in embedded and secondary networks (apartment buildings, shopping centres, retirement villages) sit largely outside this pricing reform, because they do not hold a direct relationship with the distributor or the retail market. Keith Taylor makes the parallel point for balcony and plug-in solar: it is behind-the-meter, it does not export, and it falls outside the DGPPs entirely. These are not edge cases. They are a growing share of how New Zealanders actually live and actually generate, and they are precisely the households the equity argument above is about: renters and apartment dwellers. A reform scoped to the injection connection cannot see them. That is a clear illustration that the regulatory unit needs revisiting, and it is one more item for the workstream the decision paper should name.

Closing

The submissions tell the EA two things. The four amendments are supported and should proceed on a realistic timeline. And a reform scoped to the one-way injection connection is one that solar developers, EV importers, community groups, consultants and individual citizens can already see is one cycle short of the question that matters.

Responding to that does not require widening this consultation. It requires one paragraph in the decision paper: name the workstreams that pick up onsite consumption, aggregation, the retailer-household relationship, embedded networks and the recognition of community and aggregated generation as market actors, and commit a date. The cost of doing it is a paragraph. The cost of not doing it is that the architecture gets set by whoever fills the silence, and the 2028 conversation about who captures the value of distributed generation starts from the same place 2024 did. Entrust's equity question is the test of why this matters: the way to make distributed generation fair is to make it something a renter can take part in, and that is a question of community ownership, aggregation and access this consultation's scope does not reach. The decision paper should say where it does.

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 here are mine and not those of any client. This cross-submission responds to submissions published by the Authority following the 19 May 2026 close. Submitters are characterised in good faith from their published submissions and any mischaracterisation is unintended.)

Regards,

Duane Fernandes