By email: distribution.pricing@ea.govt.nz
3rd June 2026

DGPPs reform proposals – cross-submission

SUPA Energy (SUPA) welcomes the opportunity to cross-submit in response to the Electricity Authority's Distributed Generation Pricing Principles (DGPPs) reform proposals. It is good regulatory practice to provide for cross-submissions on matters that may be contentious and/or have material implications for the efficient operation of the electricity industry.

Opportunities for non-traditional solutions as part of the energy transition

SUPA is excited about the opportunities that exist for non-traditional solutions to provide lower cost and more efficient solutions to electricity network requirements. Our submission noted electricity distributors are going through a transitional phase and are exploring the most effective ways to integrate flexibility services, DG and consumer participation into their networks.

The value proposition we offer started with opportunities to benefit from intraday price volatility and is evolving to use batteries with solar to provide distributors with non-network alternatives.

From SUPA's perspective the industry is at an immature stage with a large amount of untapped opportunities for better utilisation of distributed energy resources (DER). This isn't a criticism of the industry. It just reflects the reality that the industry is in a state of transition, and everyone is on a learning curve. Inevitably some electricity distributors will be faster to adapt, and this will provide a pathway for other distributors to see the potential benefits of alternative solutions and to be fast followers.

Framing DGPP and distribution reform in the context of decentralisation

The Motor Vehicle Industry Association (VIA) commentary on decentralisation aligns with our submissions to the Authority. SUPA for example, agrees with VIA that "the DGPP reforms should be designed for transition" and "The regulatory framework should not entrench a centralised model if technology and consumer participation are moving in a more distributed direction. Instead, it should enable a smooth transition from the system we have today to a system in which many more participants can generate, store, use, and export electricity on fair and transparent terms."

We also agree that "A more distributed system also has potential energy-independence benefits. It can allow more energy demand to be met from domestic generation and local storage, while reducing exposure to imported fossil fuels and the price shocks associated with them. <u>This does not require the Authority to predict the final structure of the electricity system. It requires rules that do not foreclose efficient distributed participation as technology evolves.</u>" [emphasis added]

Lack of evidence of size of the problem

We agree with IEGA that "The Authority has provided no specific examples to substantiate the claim that "the … approach to estimating incremental costs means most injection connections are likely subsidised by consumers" and "the Authority's impact assessment … indicates the level of subsidy … is 27 cents per ICP per annum for connections without generation" i.e. if there is a subsidy it is likely very small and immaterial.

Greater clarity needed in how incremental cost should be calculated

Our submission raised concern that the revised definition of incremental cost does not provide sufficient clarity. This was a recurring theme amongst submitters. We agree with Unison and Centralines that "Absent this clarity, there is a risk of inconsistent application across distributors, weaken investment signals and unintended cost allocation outcomes for consumers" and "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."

We share EGRANZ concern that "the reframing creates a corresponding risk in the opposite direction. If distributors interpret 'reasonable estimate' expansively, charges may drift above incremental cost, creating new subsidies that flow from producers to consumers."

We also share IEGA's concern that "As the experience with the current incremental cost principle in the DGPPs demonstrates, interpretation of the proposed 'incremental injection cost' principle is likely to differ across distributors and across different types of generation connections."

Our concerns are reinforced, in particular, by IEGA's submission including that "the proposal expands the scope of what distributors can consider an 'incremental cost' associated with connecting a generation-only site to a distribution network" and this could result in over-statement of incremental cost. We share IEGA's view that concepts like cumulative and programmatic costs need to be "sufficiently well-defined that only those costs that are incremental to injection are included".

Understatement of DG network benefits

While there were differing views on the extent to which (or if at all) the DGPPs resulted in understatement of incremental costs (see, in particular, IEGA's submission) there appears to be universal acceptance that they result in understatement of the network benefits of DG e.g. "ENA agrees that the current DGPP's can cause… benefits to be under-allocated to injection connections."

Westport, for example, submitted that "current framework" does "not provid[e] clear mechanisms to reward injection that genuinely benefits the wider community (such as deferring upgrades or improving resilience). This outcome is not consistent with community fairness." ERGANZ similarly submitted, based on gentailer member experience, that there is "Limited recognition of the network benefits provided by injection that aligns with peak offtake."

We share Lodestone's "[o]verall" commentary that "it should be openly acknowledged that distributed generation adds a clear local benefit to consumers— through reduced nodal prices at the connection node, reduced transmission losses, and deferred need for transmission investment" and "This benefit is not adequately reflected in the EA's framing, which focuses primarily on the costs DG creates and the need to recover those costs more accurately. The correct starting point for any pricing reform should be that DG is a net positive for consumers, not a cost to be managed."

Reform should ensure that benefits provided by injection are recognised with the same rigour as costs imposed

We share VIA's key concern about symmetry: "if incremental costs are more fully allocated to injection, incremental benefits must also be properly recognised and rewarded. The system should not become better at charging distributed participants for costs than it is at recognising the value they provide. Benefits should be assessed by reference to efficient system operation and long-term consumer benefit, not incumbent revenue protection or generator margins."

We similarly agree with Genesis that "Reform should ensure that benefits provided by injection are recognised with the same rigour as costs imposed."

Missing network price signals

SUPA agrees with the concerns Vector raised in its response to the ECTF's Open Letter that "there is a clear gap in pricing signals sent within the sector for the costs of impending transmission upgrades to influence consumer decision-making" given that "transmission charges … do not signal future upgrade costs at all, let alone by location." We agree with

Vector that this "missing signal" weakens the business case for alternatives by encouraging over-reliance on build solutions and under-rewarding flexibility" and "if transmission-related costs are treated inconsistently or not signalled coherently, investment will not occur on the most efficient basis." There has been a large number of submissions to the Authority, in various consultations, making similar comments and raising concerns about the lack of a LRMC and/or peak-usage transmission charges.

For the avoidance of doubt, we agree in full with Appendix 2 of Vector's ECTF submission:

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vector

Appendix 2: The missing price signal for GXP upgrades and alternatives

38. Pricing signals are the key tool used in the New Zealand electricity system to drive efficient operational and investment decision-making – including surfacing and incentivising non-network solutions. Shifting demand to avoid high prices (and take advantage of low prices) is a key motivator for market participants, as we observe in both the wholesale spot market and across distribution networks. It is therefore essential that price signals are cost-reflective, including all relevant information for influencing decision-making.

39. Vector considers there is a material gap in New Zealand's electricity price signals: the long-run, forward-looking cost of upstream transmission augmentation (including new or upgraded GXPs) is not visible in the prices any parties actually see and can respond to. This weakens incentives to use (and invest in) non-network alternatives, and risks inefficient outcomes as electrification, load growth, and DER orchestration accelerate.

40. This is problematic because:

   a) Wholesale nodal prices do not (and cannot) recover or signal the capital cost of future transmission augmentation. Nodal prices are designed to reflect *marginal energy costs* at each location, including losses and constraints, not the fixed/capital cost of building or upgrading network capacity. The market engine SPD has no visibility of future transmission upgrade costs.

   b) By design, the Authority's TPM is primarily a cost allocation / cost recovery framework, not an ex ante customer-facing price signal for future GXP reinforcement. The TPM is the method used to calculate transmission charges and allocate them efficiently between transmission customers. Those charges (benefit-based and residual) are about recovering *existing grid* costs, rather than providing a transparent, forward-looking "capacity price" that end users and flexible resource aggregators can respond to in real time or through standard retail offerings.

   c) End consumers typically do not see a clear, forward-looking, locational signal for upstream GXP / transmission augmentation in retail prices. Transmission charges, which cover *existing* assets only, are generally passed through via distributors / retailers in ways that are not uniform and often smooth costs across time and customer groups. While Vector is one of the few EDBs to pass transmission charges through on a GXP-by-GXP basis, even then, the transmission charges do not signal *future* upgrade costs at all, let alone by location.

41. By way of example, Transpower has several significant GXP upgrades and new GXPs underway in the Auckland region. But it is not signalling these costs in its TPM charges to Vector, and nor is Vector signalling these costs via its connection or lines charges.

42. In fact, the Authority's price-setting guidance to EDBs to date does not appear to have contemplated EDBs doing anything other than passing through transmission charges in as non-distortionary a way as possible. The forward-looking component(s) of EDBs pricing are instead focussed on signalling distribution-level congestion and constraints, not transmission level.

43. This "missing signal" therefore weakens the business case for alternatives to GXP upgrades. When the future cost of upstream reinforcement is not visible to the parties driving new demand/export patterns, markets will tend to:

Page 8 of 9

vector

   a) over-rely on "build" solutions (because the avoided cost is not clearly priced), and

   b) under-reward flexibility (because the system value of deferring an upgrade is not transparently monetised by avoidance of high, cost-reflective price signals that include all relevant costs).

The Authority should actively monitor application of the DGPPs

We agree with VIA that "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, and whether pricing supports electrification and distributed participation" and "Monitoring should include evidence on whether useful injection is being fairly rewarded, whether low-value injection is treated through low or zero payment rather than punitive charges, whether flexible demand is being enabled to absorb excess generation, and whether non-incumbent participants are receiving equivalent treatment where they provide equivalent system value."

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?

SUPA fully agrees with the submission of Rewiring Aotearoa. The Rewiring Aotearoa submission aligns with the submission we made in response to the Energy Competition Task Force consultation on "Requiring distributors to pay a rebate when consumers supply electricity at peak times: definition of a small business".

In particular, we agree with Rewiring Aotearoa that "the Code changes proposed in this consultation will not result in distributors providing efficient payments to all groups of customers for the benefits their injection provides, where it reduces network costs for local customers over time" and "There is a group of medium sized customers who will miss out. These are customers who are not eligible for default peak export payments (with connections over 45kVA or generation export capacity over 45kW), and who are operating small to medium sized businesses and are not well placed to negotiate a fair deal for payment for injection when it provides benefits."

SUPA urges the Authority to take heed of the Rewiring Aotearoa and SUPA submissions and revisit its approach to defining 'small' versus 'large'. As it stands, it is reasonable to expect that a large amount of DG (and DER) will 'fall between the cracks' and Authority network pricing reform will not fully realise the potential opportunities and benefits DG (and DER) can provide to the broader, and efficient, operation of the electricity industry.

Key recommendations

SUPA Energy encourages the integration of non-traditional solutions, such as batteries with solar, to provide distributors with non-network alternatives. The industry is in transition, and there are untapped opportunities for better utilisation of distributed energy resources. Following consideration of submissions our recommendations for reform of the DGPPs include the following:

1. **Recognise and Reward Distributed Generation Benefits:** SUPA strongly recommends that the Authority ensures the benefits provided by DG are recognised and rewarded with the same rigour as the costs imposed. The system should not become better at charging distributed participants for costs than it is at recognising the value they provide.

2. **Clearer Definitions and Consistent Application of Incremental Costs:** SUPA urges the Authority to provide clearer definitions of incremental costs and ensure consistent application of DGPPs across distributors. Ambiguity in the definition risks inconsistent application, weakened investment signals, and unintended cost allocation outcomes for consumers. Concepts like cumulative and programmatic costs must be well-defined so only costs genuinely incremental to injection are included.

3. **Active Monitoring by the Authority:** SUPA recommends that the Authority actively monitor the application of DGPPs. Monitoring should ensure electricity distributors recognise benefits as well as costs, methodologies are consistently applied, small participants can respond to pricing signals, and pricing supports electrification and distributed participation. Evidence should be gathered on whether useful injection is fairly rewarded and whether flexible demand is enabled to absorb excess generation.

4. **Address Missing Network Price Signals:** SUPA agrees with concerns about missing pricing signals for impending transmission upgrades. Transmission charges do not signal future upgrade costs, weakening the business case for alternatives and under-rewarding flexibility. The Authority should address this gap to encourage efficient investment decisions.

5. **Bespoke Approach for Larger Connections:** SUPA supports a more bespoke approach for larger connections, as opposed to the broad-based approach used for residential and small business consumers. The current Code changes may not result in efficient payments to all groups of customers for the benefits their injection provides, especially medium-sized customers who fall between the cracks. The Authority should revisit its approach to defining ‘small’ versus ‘large’ to fully realise the potential opportunities and benefits DG and DER can provide.

Concluding remarks

SUPA Energy supports reform of the DGPPs to better recognise and reward the benefits of distributed generation. More work is needed to ensure clearer definitions of incremental costs, consistent application across distributors, and robust monitoring to ensure costs and benefits are treated symmetrically. All participants—especially those providing genuine network value—should be fairly compensated and incentivised in the evolving electricity market.

Yours sincerely,

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