Maximising benefits from local electricity generation

Submission to the Electricity Authority
Consultation on Distributed Generation Export Limits (10 kW Single Phase)

Executive Summary

Three of New Zealand's most forward-thinking electricity distribution businesses — Aurora Energy, Powerco, and Northpower — have already raised their single-phase export limits to 10 kW without waiting for regulation. This submission supports adopting the 10 kW limit nationally, followed by an urgent consumer-centric transition: DSOs publish real-time visibility and price signals so flexible Home Energy Management Systems (HEMs) can respond automatically. As homes electrify and adopt EVs, some will need systems larger than 10 kW — ideally three-phase and V2G-ready — so exports are phase-balanced, winter-capable and locally useful. Shared-savings (not subsidies) should recognise avoided upgrades.

1. Background and Context

New Zealand's very high penetration of smart meters means low-voltage (LV) visibility already exists at most ICPs. If the Electricity Authority and Government unlock ICP-level power-quality and voltage data via the new Consumer Data Right (CDR) framework, EDBs can perform a Distribution System Operator (DSO) role without installing thousands of new monitoring devices. This enables transparent feeder dashboards, near-real-time hosting-capacity maps, and automated price/voltage signals for HEMs.

Experience in Australia shows that lifting export limits works best alongside visibility and coordination. DNSPs like SA Power Networks and Energex have implemented flexible exports and dynamic connections based on live voltage and congestion data. Early movers in New Zealand are proving the same approach is practical here.

2. Six Supporting Measures

2.1 Collaborative visibility and consumer participation

Consumers and networks should work together using shared data. DSOs can publish simple online dashboards showing local voltage, congestion, and available capacity in near-real-time. This allows flexible HEMs to automatically choose the best times to charge EVs, heat water, or export solar energy. Instead of blunt export limits or curtailment, households respond to transparent price and voltage signals. This participatory approach turns consumers into partners in stability, not passive users restricted by static limits.

2.2 Dynamic Operating Envelopes (DOEs)

Dynamic export limits allow each inverter to adjust automatically to network conditions — exporting more when voltage is low and less when it is high. This approach has been proven through large-scale Australian trials and could easily be adopted here. The communication uses open international standards such as IEEE 2030.5 — known in Australia as CSIP-Aus (Common Smart Inverter Profile). These standards ensure that all inverter brands and energy systems can "speak the same language", enabling consistent and secure coordination. DOEs are like variable speed limits on a road: when conditions are clear, you can go faster; when it's congested, everyone slows down a little to keep traffic flowing.

2.3 Phase balance and three-phase evolution

As households electrify and add EVs, some will naturally need systems larger than 10 kW. Encouraging these homes to upgrade to three-phase connections spreads load evenly, reduces voltage rise, and helps the grid run more smoothly. Rather than viewing this as a burden, distributors can treat it as a co-investment opportunity — every home that upgrades reduces the need for transformer and feeder reinforcement. This is a fair trade-off: consumers invest in better connections, while DSOs save on avoided upgrades.

2.4 Price-neutral three-phase and shared-savings credits

Today, many households that install three-phase supply pay higher daily fixed charges, even when their overall capacity is no greater than a single-phase home. This penalises behaviour that actually helps the network. Three-phase should be price-neutral for standard residential capacity. Instead of subsidies, distributors and consumers should share the savings from deferred upgrades. For example, homes that provide proven phase balance or voltage stability could receive small export uplifts or annual credits reflecting the avoided cost of new infrastructure.

2.5 Vehicle-to-grid (V2G) and peer-to-peer trading

Electric vehicles hold the key to large-scale flexible storage. When connected through bidirectional chargers, EVs can export power back into the grid during evening peaks or local shortages. Three-phase chargers make this process smoother by balancing export across all phases. With DSOs providing open data and fair market rules, households will be able to trade their stored energy peer-to-peer, supplying nearby homes or businesses. This creates a resilient, community-based energy ecosystem — not one controlled solely from the top down.

2.6 Dynamic Locational Marginal Pricing (DLMP)

Dynamic Locational Marginal Pricing (DLMP) represents a fundamental change in how distributors earn revenue and manage efficiency. Instead of being rewarded for building more assets, distributors would earn revenue for operating their networks efficiently — keeping supply close to demand. This reflects the physical reality of electricity: it flows along the path of least resistance, and the closer generation is to consumption, the lower the losses and costs. DLMP turns these local efficiencies into transparent price signals. When prices rise in an area, it invites nearby consumers, batteries, or V2G systems to help; when prices fall, it signals that capacity is available. This model rewards collaboration, not expansion.

3. Implementation Pathway

The Authority could begin with a one-year pilot involving several feeders operated by early-moving EDBs such as Aurora Energy, Powerco, and Northpower. Each would publish live voltage and capacity data, implement per-phase dynamic envelopes, and offer price-neutral three-phase connections. Participating households could receive modest credits for providing phase balance or supporting local voltage stability. Performance would be measured by reduced voltage excursions, improved phase symmetry, and avoided reinforcement expenditure.

4. Conclusion and Recommendation

The 10 kW single-phase limit is an enabling milestone, but it should also signal a new direction. New Zealand can move from centralised control toward a consumer-centric grid built on data transparency, local participation, and shared benefits. Unlock ICP-level smart-meter data via CDR so DSOs can coordinate CER using open standards and price signals, not blunt curtailment.

By codifying what forward-looking EDBs have already demonstrated — and by promoting DSOs that publish real-time grid visibility and price signals — the Electricity Authority can accelerate electrification, strengthen resilience, and empower households to generate, store, and trade clean, home-grown energy.

References

1. EA consultation on export limits (default 10 kW, inverter settings, etc.).

Electricity Authority – Consultation: Maximising benefits from local electricity generation (export limits)

2. Aurora Energy: raising single-phase export limit to 10 kW (media release).

Aurora Energy – media release: single-phase export limit to 10 kW

3. Powerco: policy page (now allowing 10 kW) + NODS agreement with Bluecurrent (≈250k meters).

Powerco – DG up to 10 kW (policy + standard)

Powerco – NODS agreement with Bluecurrent (250,000 meters)

4. Northpower: 10 kW single-phase announcement + renewable energy page.

Northpower – single-phase export limit to 10 kW

5. WEL Networks: 5-minute AMI data across 68,600 meters (LV visibility).

WEL Networks – 5-minute data across 68,600 meters (LV visibility)

6. Orion ViSION: 5-minute operational data via Bluecurrent; lessons on access.

Orion – ViSION project report: 5-minute operational data via Bluecurrent

7. MBIE: Consumer Data Right / CPD Act and **Open Electricity** designation pages.

MBIE – Customer and Product Data Act (Consumer Data Right) overview

MBIE – Open electricity designation (CDR for electricity)

8. EA: "Data for better performance—unlocking smart meter value" (SPE 2024/25).

EA – Statement of Performance Expectations 2024/25 (unlock ICP data)

9. AEMO Project EDGE (final report hub + ARENA knowledge bank).

AEMO – Project EDGE (Final Report + resources)

10. SA Power Networks Flexible Exports (program & eligibility checker).

SA Power Networks – Flexible Exports (program, eligibility, results)

11. CSIP-Aus (IEEE 2030.5 profile).

CSIP-Aus – Common Smart Inverter Profile (IEEE 2030.5 based)

Graeme Weston (Consumer/prosumer)
2 November 2025

Appendix B Format for submissions

Maximising benefits from local generation

Submitter	**Graeme Weston**
Submitter's organisation	**Consumer/Prosumer**

Please send your submission to connection.feedback@ea.govt.nz by **5pm, Wednesday 19 November 2025**

Questions	Comments
Q1. What are your views on the proposal to set a default 10kW export limit for Part 1A applications?	A 10 kW single-phase limit is **sufficient to meet most households' winter needs**, particularly as heating, hot water, and EV charging increase. However, in summer this capacity will often produce **significant surplus generation**, which if unmanaged could create local voltage issues. Rather than curtail this clean energy, **EDBs and DSOs should plan now** to harness it — through **dynamic operating envelopes (DOEs)**, **local energy trading**, **community storage**, and **vehicle-to-grid (V2G)** participation. With real-time visibility and responsive HEMs, this surplus can strengthen the grid and lower costs instead of being wasted.
Q2. What are your views on the Code clarifying that a distributor cannot limit the nameplate capacity of a Part 1A application, unless the capacity exceeds 10kW?	The 5 kW limit was always understood by EDBs to be technically conservative and unlikely to cause network issues, yet it was enforced as a blanket rule. While this was permissible under existing standards, it represented **risk aversion rather than leadership** in preparing for the energy transition. Going forward, we need EDBs to **proactively enable** distributed energy rather than constrain it — using smart-meter data, real-time visibility, and dynamic operating envelopes to manage local voltage rather than rely on static export limits.
Q3. There are requirements for distributors in Proposal A1. Which	Current inverter settings are often **locked by administrators**, preventing customers from using the full functionality of their devices. This can **conflict with more effective, customer-led**

of these do you support, or not support, and why?	**ways of managing grid stability** such as smart HEMS or aggregated flexibility controls. EDBs require **clear guidance and visibility** rather than restrictive control. Without access to real-time LV data, they are effectively operating blind on "our" shared grid — the same network consumers invest in through their DER assets. The Electricity Authority should require EDBs to use **existing AMI data (via the Consumer Data Right)** to gain visibility, rather than rely on restrictive administrative settings. The goal should be **coordination, not control** — enabling DSOs and consumers to collaborate using data and price signals, rather than locking down flexibility through centralised limits.
Q4. What are your views on the proposal for industry to develop an export limits assessment methodology?	**Learn from Australia, act now** • **Use AMI via CDR now:** Mandate ICP-level voltage/PQ access so DSOs can run LV visibility without new hardware; publish feeder/phase dashboards. • **DOEs as signals (not hard commands):** Publish per-phase headroom + locational prices; define control hierarchy (inverter = safety, HEMS = optimisation, DSO = signals). • **Three-phase pathway for >10 kW:** Make residential three-phase price-neutral; set a simple national imbalance limit; fast-track upgrades where it avoids reinforcement. • **Shared-savings, not subsidies:** Offer small credits/export uplifts tied to **avoided capex** and proven stability (phase balance, voltage hygiene). • **V2G readiness:** Prefer three-phase bidirectional chargers; allow P2P participation; enrol EVs in DOEs for evening peaks. • **Interoperability + standards:** Require open APIs (IEEE 2030.5/CSIP-Aus, OCPP) and data portability; avoid vendor lock-in. • **Equity and rentals:** Support participation for renters/social housing (portable EV/V2G, controlled loads) so benefits aren't limited to homeowners. • **Installer guidance + accreditation:** One-page national guide (when to specify three-phase & V2G-ready); recognise HEMS competence in approvals.

	• **Regulatory sandbox + KPIs:** 12-month feeders pilot; targets: over-voltage minutes ↓ ≥50%, phase-spread events ↓ ≥50%, curtailment ↓ ≥30–50%, documented capex deferral. • **Fallback & consumer protections:** If data/control fails, revert to conservative static export + grid-support modes; clear dispute/escalation path. **Bottom line:** Act early with transparency, open standards, and shared-savings. Let consumers and DSOs collaborate via price/visibility signals so we avoid Australia's "cap first, fix later" trap.
Q5. What would you do differently in Proposal A1, if anything?	An **online registration form**, linked through the **Consumer Data Right (CDR) "Open Electricity" framework**, should allow consumers or their installers to directly update EDB databases with details of installed or planned flexible devices — such as PV, batteries, EV chargers, and controlled loads. This visibility is essential for DSOs to identify where flexibility exists and to plan local balancing or congestion relief efficiently. Participation should be treated as a **normal user responsibility**, not voluntary — similar to how meter data is shared today. It ensures that grid operators have accurate information while avoiding unnecessary **administration costs** currently charged by EDBs for manual connection assessments. This streamlined, CDR-enabled process would lower costs, improve transparency, and let DSOs coordinate flexibility safely and fairly without needing expensive new monitoring systems. .
Q6. What concerns, if any, do you have about requiring the 2024, rather than 2016, version of the inverter installation standard for Part 1A applications?	**Support the 2024 direction** (10 kW single-phase, modern inverter settings) as a pragmatic step—**provided** it's paired with consumer-centric measures. **Expectations for the next iteration (commit in principle now, deliver over 12–18 months):** 1. **Unlock AMI data via CDR:** ICP-level voltage/PQ access for designers and HEMs; no new hardware. 2. **DOEs as signals, not hard commands:** Publish per-phase headroom + **locational**

	prices; define control hierarchy (inverter = safety, HEMS = optimisation, DSO = signals). 3. **Phase balance rule + three-phase pathway:** A simple national imbalance limit and a clear path for >10 kW homes to move to **three-phase** (price-neutral at residential kVA). 4. **Shared-savings incentives:** Small annual credits/export uplifts where customer upgrades **avoid reinforcement** (no subsidies; share avoided cost). 5. **V2G readiness:** Prefer three-phase bidirectional chargers for high-power export; enrol in DOEs and allow P2P participation. 6. **Real-time visibility:** DSO dashboards/API showing feeder/phase voltage and congestion so flexible HEMs can respond. 7. **DLMP pilots:** Tie a small slice of EDB revenue to **local performance** (voltage spread, congestion, losses) to reward efficient operation. 8. **Installer guidance:** Publish a one-page national guide: "When to specify three-phase & V2G-ready" (≥8–10 kW PV, two EVs, all-electric). 9. **KPIs & timeline:** Over-voltage minutes ↓ ≥50%, phase-spread events ↓ ≥50%, curtailment ↓ ≥30–50%; pilot report-back in 12 months. **Bottom line:** 2024 settings are fit for purpose; the next iteration should lock in **data access, price signals, and shared-savings** so consumers, HEMs, and DSOs collaborate—and upgrades are the last resort, not the default.
Q7. Do you support amending the New Zealand volt-watt and volt-var settings to match the Australian values for Part 1A applications - why or why not – what do you think are the implications?	These should be **last-resort tools** to safeguard the shared grid, activating only when genuine stress is occurring. Under normal operation, **Dynamic Operating Envelopes (DOEs)** should adjust exports proactively and gradually — long before conditions become critical — so that network stability is maintained without disrupting consumer generation or autonomy. This ensures grid safety while preserving public trust and confidence in the fairness of distributed generation controls.

Q8. What would you do differently in Proposal A2, if anything?	Support the flexibility it offers but require that any EDB-set export limits are **evidence-based, transparent, and consistent**. Specifically, limits should be justified using **smart-meter (AMI) voltage data** made accessible through the **Consumer Data Right (CDR)** so DSOs can demonstrate real network constraints without extra monitoring costs. The EA should also provide **national guidance on control hierarchy** to prevent conflicts between inverter software, distributor controls, and consumer HEMs. This ensures fairness, consumer trust, and efficient use of existing infrastructure.
Q9. Do you have any concerns about the Authority citing the Australian disconnection settings for inverters when high voltage is sustained?	If the system can operate safely, there is **no reason to restrict generation**. Control measures should be **last-resort tools**, activated only when the network is under genuine stress. With smart-meter visibility and **Dynamic Operating Envelopes (DOEs)** in place, DSOs can anticipate issues and adjust exports smoothly, long before critical limits are reached. Under **Dynamic Locational Marginal Pricing (DLMP)**, this operational flexibility actually becomes an **opportunity** — EDBs can **earn more revenue by efficiently delivering local energy over their existing assets**, effectively "**sweating the network**" instead of building new capacity. This rewards proactive, data-driven management and aligns EDB incentives with consumer participation and overall system efficiency.
Q10. Do you have any concerns about the Authority requiring the latest version of the inverter performance standard for Part 1A applications?	The proposal should proceed **provided it meets the aims outlined above** — enabling visibility, consumer participation, and proactive management through DOEs, HEMs, and CDR data access. If these supporting measures are not yet in place, then the regulatory framework will need an **urgent upgrade** to ensure safety, transparency, and fairness under higher export limits. This is an **opportunity for New Zealand to learn from Australia's experience and lead**, showing how proactive visibility, open data, and collaboration can unlock growth in distributed generation without costly grid upgrades.

Q11. What are your views on the proposal that where distributors set bespoke export limits for Part 2 applications, they must do so using the industry developed assessment methodology?	A **bespoke approach** may be justified where existing grid assets are **sub-standard or nearing capacity**, but any deviation should remain **consistent with national standards**. Upgrades should proceed only where they clearly **enhance the network's ability to host future distributed generation and manage flexibility**, not simply to maintain outdated configurations. Any bespoke work should also **feed learnings back into national design standards**, so each upgrade helps lift overall system performance and resilience.
Q12. What are your views on the several requirements that must be adhered to regarding the distributors' documentation (see paragraph 5.96) relating to setting export limits under Part 2?	Paragraph 5.96 appropriately recognises the need for EDB discretion, but it must be exercised **to lift standards, not lower them**. We support discretion **only where it demonstrably improves network capability**—for example, by trialling smarter technologies, data sharing, or flexibility tools that enhance the grid's future performance. Any such variations should use **smart-meter evidence**, be **fully transparent**, and **feed learnings back** into national standards so innovation raises the baseline for all. This ensures discretion becomes a **pathway for improvement**, acknowledging the **smart ideas and technologies that will inevitably emerge**.
Q13. Do you agree it is fair and appropriate that where distributors set export limits for Part 2 applications, applicants can dispute the limit? If so, what sort of process should that entail?	The EA appears too focused on allowing EDBs to **lower technical or connection standards**, rather than expecting them to continuously improve. Discretion should not become a back door for restriction; it should be a **mechanism for innovation and uplift** — supporting pilots, smarter tools, and modernised practices that raise overall capability. Consumers have already invested in intelligent devices; regulation should ensure those capabilities are **enabled, not disabled**. **New Zealand's credibility as a flexible-grid leader depends on raising—not relaxing—standards.** By setting clear expectations that discretion must deliver measurable improvement, the EA can encourage EDBs to demonstrate leadership, share learnings, and build public trust in the transition to a smarter, more efficient grid.

Q14. What would you do differently in Proposal B, if anything?	Proposal B would **re-centralise control with EDBs** and risk recreating the very fragmentation and inconsistency that this review aims to fix. While flexibility is important, removing the national default would **undermine consumer confidence** and create barriers for installers and aggregators. Instead, the EA should retain a **national 10 kW baseline** (Proposal A1) and build on it with the **supporting measures already outlined** — open data via CDR, DOEs as visibility signals, three-phase evolution, and shared-savings incentives. If Proposal B proceeds at all, it should only be as a **limited sandbox mechanism** for EDBs that commit to transparency, public reporting, and data sharing. **Bottom line:** keep a clear national standard that protects consumers, but allow innovation under open, evidence-based conditions — not through deregulation.
Q15. What are your thoughts on requiring the inverter performance standard (AS/NZS 4777.2:2020 incorporating Amendments 1 and 2) for low voltage DG applications in New Zealand?	We support full alignment with **AS/NZS 4777.2:2020 (Amd 1 & 2)** for inverter safety and grid-support functions (Volt-Var, Volt-Watt, frequency-watt). To coordinate flexibility at scale, the Authority should **lead with OpenADR (2.0)** as the **primary signal layer** for events/prices/needs to **HEMs and aggregators**, and use **IEEE 2030.5/CSIP-Aus** only where device-level telemetry or safety functions are required. **Control hierarchy to avoid conflicts:** • **Inverter:** safety & autonomous grid-support per 4777.2. • **HEMS/Aggregator:** optimisation in response to **OpenADR** signals (prices, DOEs published as visibility/price). • **DSO/SO:** publish visibility and price via **OpenADR**, not hard device commands. • **Fallback:** if signals fail, devices revert to conservative static export within 4777.2 settings. This approach preserves a single trans-Tasman equipment market (4777.2 + 2030.5/CSIP-Aus), **prevents controller conflicts**, and accelerates consumer-centric flexibility by using **OpenADR** for

	market signals while retaining 4777.2 compliance for device behaviour.
Q16. Do you consider the transitional arrangements workable regarding requirements and timeframes? If not, what arrangements would you prefer?	Delays and piecemeal rules force consumers to "do it twice" — they can't fully utilise their roof the first time, then must revisit later at **high labour cost**. To avoid costly rework, the EA should enable a **single-visit pathway** now: • **Allow three-phase, up to ~15 kW** for homes that enrol in **DOEs** and meet **phase-balance** and **4777.2** settings — even where only **40/60 A fuses** are available. Use **export caps via DOEs** initially, with uplift as headroom permits. • Make **three-phase price-neutral** at residential capacity and **fast-track approvals** for designs that include HEMS optimisation and per-phase balance. • Permit **staged commissioning** (all hardware installed once; temporary DOE export cap) so roofs aren't revisited when regulations catch up. • Require EDBs to **publish the 3-phase pathway** and the criteria for moving from temporary caps to higher exports, using **AMI evidence** rather than repeated site visits. This approach prevents stranded labour, supports electrification (EVs, winter coverage), and delivers a fair, future-ready outcome without waiting for another regulatory cycle.
Q17. What are your views on the objective of the proposed amendments?	EDBs should **publish feeder plans** showing how much three-phase uptake is needed to keep LV stability manageable **without major upgrades** as EVs and PV scale. For example: *"On Feeder X, modelling indicates* ***~30% of ICPs with three-phase inverters*** *(or equivalent phase-balancing via HEMS/V2G) maintains voltage and phase symmetry within targets at high PV/EV penetration."* **What the plan should include:** • **Targets per feeder:** % ICPs needing three-phase or phase-balancing capability (e.g., 25–35%).

	• **Assumptions:** EV uptake, PV size mix, typical fuse ratings (40/60 A), winter vs summer scenarios. • **Levers:** DOEs (per-phase), HEMS response, V2G participation, hotspot mitigation (tap changes, minor reconductoring). • **Triggers & timelines:** When targets are met, when export caps lift, when upgrades are actually required. • **Evidence:** AMI voltage/phase data published via **CDR/Open Electricity** dashboards. This makes expectations clear for consumers/installers, enables **single-visit** designs (go three-phase now), and lets DSOs **sweat existing assets** instead of defaulting to capex.
Q18. Do you agree the benefits of the proposed amendments outweigh their costs? If not, why not?	If EDBs focus on **proactive planning and data transparency**, the need for physical upgrades will be minimal. What's required is genuine **collaboration between EDBs, installers, designers, and customers** to find the **least-cost, highest-benefit solutions** — such as targeted three-phase upgrades, phase balancing, or flexible demand participation. By sharing feeder data and forward plans early, EDBs can enable consumers to design once, invest confidently, and avoid costly rework. The Electricity Authority should **incentivise collaboration outcomes** — for example, through shared-savings or avoided-capex credits where joint planning defers infrastructure upgrades. **No plan is a plan to fail**: without open collaboration and clear feeder-level roadmaps, costs rise for everyone and the transition slows unnecessarily. Under a **Dynamic Locational Marginal Pricing (DLMP)** model, this shift also flips EDB revenue from **capex expansion to operational efficiency** — rewarding networks for **sweating existing assets and maintaining stability with smart tools rather than new hardware**.
Q19. What are your views on the Authority's estimate of costs of lost benefits from a 5kW export limit?	**Lost benefits and social licence:** The historic 5 kW cap constrained exports even where feeders had headroom (built for peaks), creating **avoidable lost benefits** and eroding consumer trust. Early adopters must now revisit

	systems and pay extra to realise the EA's stated goal of maximising production and benefits. While Aurora, Powerco and Northpower have corrected course at 10 kW, **confidence will only be rebuilt** if we pair higher limits with transparency (CDR/AMI data), DOEs-as-signals, and a price-neutral pathway to three-phase for larger, electrified homes. Recognise the **lost benefits and social licence damage** from the legacy 5 kW cap and move beyond 10 kW by establishing a **three-phase pathway to 15–20 kW total** for electrified homes (2 EVs, all-electric) with **DOEs as signals**, per-phase limits, and **price-neutral three-phase** at residential capacity. Avoid **15 kW on single-phase** (exceeds practical 63 A margin); instead, publish feeder-level headroom and phase-balance targets, unlock **CDR/AMI voltage data**, and adopt **shared-savings** so EDBs "sweat assets" and consumers design **once**. This repairs trust and aligns incentives without defaulting to blunt curtailment.
Q20. Are there costs or benefits to any parties (eg, distributors, DG owners, consumers, other industry stakeholders) not identified that need to be considered?	Left to legacy settings, the transition risks looking unfair: **EDBs spend little beyond planning**, while **installers visit twice**, **DG owners pay twice**, and **consumers keep paying high prices** until competition from cheap sunshine finally forces fossil out. Trust erodes. **Do it right with a managed glide-path:** • **DSO model, not capex-first:** EDBs publish feeder headroom/phase data (via **CDR/AMI**), run **DOEs as signals**, and **sweat existing assets**. Curtailment becomes last-resort. • **Single-visit designs:** Permit three-phase pathways (15–20 kW total) with staged export caps (DOEs) so roofs aren't revisited when rules catch up. • **Price-neutral three-phase + shared-savings:** Neutral daily charges at residential kVA; credit customers where upgrades **avoid reinforcement**. • **DLMP incentives:** Flip EDB revenue from capex expansion to **operational efficiency**—get paid for moving energy locally and maintaining stability with smart tools.

	P2P readiness with OpenADR: Treat price/needs as **market signals** (OpenADR) to HEMs/aggregators; keep 4777.2/2030.5 for device safety/telemetry. **Consumer dividend recycling:** As fossil imports decline, channel a portion of public savings into **bill credits for low-income households** and **connection support** (e.g., three-phase, smart chargers). **Orderly gentailer glide-path:** Expect pressure on gentailer margins as **P2P and V2G** grow. Mitigate with: **Flexibility markets** they can participate in (retail orchestration, local hedges), **Performance-based returns** for DSOs (DLMP KPIs), **Transparent prudential/settlement** for P2P so reliability and security are maintained. **Workforce & trust:** Publish **feeder transition plans**, set **clear KPIs** (over-voltage minutes ↓ ≥50%, curtailment ↓ ≥30–50%), and fund **installer upskilling** for HEMS/V2G. “No plan is a plan to fail.” **Bottom line:** Cheap sunshine will win. The EA’s job is to **make the landing fair**—shift EDB incentives to operation (DLMP), unlock data (CDR), enable **single-visit** designs and **P2P/V2G**—so consumers, installers, and DSOs all benefit on the way to fossil-free.
Q21. Do you agree the proposed Code amendments are preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority’s main statutory objective in section 15 of the Electricity Industry Act 2010	S.15 is the **legal foundation** required to enable the consumer-centric, data-driven, and distributed model described above. The Electricity Authority and MBIE must jointly establish a **statutory framework** that: **Defines the Distribution System Operator (DSO) role** — making visibility, open data, and collaboration *core legal duties* of EDBs, not discretionary activities. **Mandates the release of ICP-level AMI data** under the **Consumer Data Right (Open Electricity)** so that planners, designers, aggregators, and households can participate transparently. **Recognises Dynamic Operating Envelopes (DOEs)** and **Dynamic Locational Marginal Pricing (DLMP)** as standard market instruments — giving them

	explicit standing under the Code and enabling EDB revenue to shift from capex returns to performance-based income. 4. **Protects consumer agency** — establishing that control signals (OpenADR, DOEs) are visibility and price mechanisms, not remote commands, ensuring optimisation remains with the consumer's HEMS or aggregator. 5. **Aligns all existing Acts and Codes** (Electricity Industry Act, Part 6 of the Code, the Consumer Data Right regulations, and the Distribution Pricing Principles) to remove conflicts that currently slow distributed-energy participation. 6. **Requires transparency and accountability** — public reporting of LV voltage metrics, phase balance, curtailment minutes, and shared-savings outcomes. This reform is indeed ambitious, but **it's the necessary legal scaffolding** for a modern, flexible, low-carbon grid. Without it, the transition will remain patchy, slow, and inequitable. With it, New Zealand can **lead globally** — proving that open data, smart pricing, and collaborative regulation can replace the old capex-driven model while lowering costs for everyone.
Q22. Do you agree the Authority's proposed amendments comply with section 32(1) of the Act?	Section 32(1) of the *Electricity Industry Act 2010* gives the Electricity Authority both the **power and the duty** to make and amend the Code *for the long-term benefit of consumers* by promoting competition, reliability, and efficiency. That mandate is already sufficient to act; it does not require new legislation or prolonged consultation cycles. The Authority is therefore **obliged to move decisively**—to convert consultation findings into rules that enable open data, dynamic operating envelopes, and performance-based pricing (DLMP). Continued delay or incrementalism now causes **tangible consumer harm**: stranded solar investment, repeated site-work costs, avoidable curtailment, and erosion of trust in both EDBs and the regulatory process. Acting under section 32(1) means exercising leadership, not caution. The Authority has the statutory backing to:

	• mandate **data transparency** through the Consumer Data Right; • formalise the **DSO role** for visibility and coordination; • embed **DLMP and DOEs** as standard tools for flexibility; and • ensure that network and market design evolves in step with technology and consumer capability. **In short:** the EA already holds the keys. Each year of delay deepens inequity and foregoes proven consumer savings. The *long-term benefit of consumers* now depends on **timely rule-making**, not further consultation.
Q23. Do you have any comments on the drafting of the proposed amendment?	No further technical comments. We simply urge the Authority to act with the urgency that Section 32(1) already empowers — translating years of consultation into practical, enforceable rules that enable participation, restore trust, and lower costs for consumers. New Zealand has the tools, data, and technology today; what's missing is timely regulatory courage.

Definition of Small Business – Code Amendment Proposal

This submission responds to the Electricity Authority's consultation requiring distributors to pay negative charges to reward households and small businesses for exporting power to the network during peak times.
It is grounded in a simple principle: anyone supplying goods or services that reduce system cost or improve reliability should be rewarded.
In the past, this was considered too difficult to measure or administer—but with today's technology, it can be done.
This submission avoids incumbent pushback, suggests how following a technical path will render the current <45 kVA definition debate redundant.

1. The Real Issue

The current argument over the definition of *"small business consumer"* is a distraction.
The system challenge is not definitional—it is **technical and institutional**:

1. **The EA has yet to implement dynamic DSO orchestration.**
   Distributors still operate as passive asset managers, not as real-time coordinators of LV resources.
2. **EDBs lack LV visibility.**
   Without ICP-level voltage and phase data, they cannot manage feeders dynamically.
   Blind injection can be counter-productive—raising local voltages, overloading phases, or worsening congestion when the intent was to help.
   Real-time data and Dynamic Operating Envelopes are therefore essential prerequisites for efficient, safe participation.
3. **Smart-meter owners (MEPs) have withheld data.**
   They control information consumers have already paid for and under CDR own, preventing DSOs from using it to maintain local stability.

Under Section 32(1) of the *Electricity Industry Act 2010*, the EA has both the **power and the duty** to amend the Code for the long-term benefit of consumers by promoting competition, reliability, and efficiency.
Consumers request the EA to exercise that duty effectively.

2. The Fix: Move from Definition to Performance

Instead of entrenching size limits, the EA adopt a performance-based framework that measures and rewards *actual LV support*:

1. **Unlock Smart-Meter Data.**
   Require MEPs to offer standard, non-discriminatory access to ICP-level consumption and power-quality data (≥ 5-min cadence).
   Back this with MBIE's *Customer and Product Data Act 2025* to enable "Open Electricity."
2. **Mandate DSO Operation.**
   Require EDBs to act as DSOs, publishing feeder-level dashboards and Dynamic Operating Envelopes (DOEs) that define real-time headroom for export and import.
3. **Introduce Dynamic Locational Marginal Pricing (DLMP).**
   Begin pilots so that payments follow *measured locational value*—where and when injection reduces losses or defers reinforcement.

4. **Ensure Three-Phase Price-Neutrality.**
   Remove higher daily charges for standard residential three-phase to provide phase balance and share the savings from avoided EDB upgrades.

Once these are in place, the <45 kVA threshold becomes superfluous.
The market can reward any participant—regardless of size—whose measured behaviour supports the LV network.

3. Transitional Guardrail (if retained)

If the Authority insists on a threshold while visibility and pricing mature:

- Treat <45 kVA as a temporary proxy for LV connection, not a long-term rule.
- Include a sunset date (e.g., 12 months).
- Allow case-by-case exceptions where larger LV assets (community batteries, marae systems, EV hubs) demonstrably improve LV stability.

This prevents the cap from becoming a barrier to innovation and community-scale participation.

4. Evidence of Feasibility

Several EDBs already demonstrate that mass-market export and LV visibility are practical now:

- **Powerco** – 10 kW single-phase export, 5 ¢/kWh winter peak rebate, LV visibility via a 250 000-meter NODS/Bluecurrent programme.
- **Aurora Energy** – 10 kW export limit effective 1 Aug 2025 with smart-meter voltage control.
- **Northpower** – 10 kW export enabled through LV visibility.
- **WEL Networks** – 5-minute LV operational data across 68 600 meters.
- **Orion** – "ViSION" 5-minute LV analytics.
- **Counties Energy** – DSO coordination pilots with Transpower and EECA.

These EDBs prove the tools exist; resistance from others is commercial inertia, not technical constraint.

5. Accountability and Enforcement

If data holders or EDBs continue to obstruct progress:

- The EA should refer the matter to the Commerce Commission for a market study into smart-meter data access and recommend stronger remedies.
- If necessary, critical LV data should be regulated as common-carrier infrastructure to guarantee fair, cost-reflective access.

6. Closing Statement

The <45 kVA threshold may serve as a short-term guardrail, but it must not become a barrier.
The Authority's obligation under s32(1) is to lead, not to be gamed by definitional minutiae.
Implement LV visibility, dynamic DSOs, DOEs, and DLMP so that remuneration follows measured LV benefit.

Support EDBs already modernising, and put the rest on notice to adapt or exit.
Only then will negative charges reward all who strengthen the grid—and the consumer will receive the long-term benefits promised by the Act.

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7 November 2025