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Submissions Team
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Tēnā koutou,

CROSS-SUBMISSION: Improving information on high-voltage network capacity

Nexbe Limited (Nexbe) welcomes the opportunity to provide this cross-submission on the Electricity Authority's (Authority) consultation paper, *Improving information on high-voltage network capacity*, dated 5 May 2026.

As a certified New Zealand Metering Equipment Provider (MEP) and a designer and manufacturer of low-voltage (LV) grid monitoring hardware, Nexbe occupies a unique operational position in this consultation.

We sit at the practical intersection of electricity distribution, advanced IoT hardware engineering, and live telemetry ingestion. Our perspective is drawn from the field deployment of physical sensors mapping the dynamic thermal, voltage, and harmonic realties of distribution substations across Aotearoa.

We have reviewed the primary submissions submitted by Electricity Networks Aotearoa (ENA), individual Electricity Distribution Businesses (EDBs), access seekers, and peer technology providers. While we support the Authority's ambition to unlock a digitalized electricity system, our cross-submission highlights a clear technical hurdle: High-voltage network hosting capacity cannot be modelled, planned, or published accurately in isolation from the low-voltage grid edge.

Across the primary submissions, distributors highlighted the substantial expense and IT friction of achieving dynamic network visibility. Specifically, Network Tasman and Powerco referenced the legacy Sapere report (which estimated low-voltage monitoring costs at $160m-$214m over ten years), while Vector noted the ongoing barrier of incomplete smart meter access from Metering Equipment Providers, and Westpower projected over $400,000 in compliance costs for their regional network.

Representing edge hardware and telemetry expertise, Nexbe submits that these primary pushbacks rest on an obsolete architectural assumption and outdated costing methodology.

Our cross-submission is anchored in three core propositions:

1. **The historic cost pushbacks assume heavy legacy IT.** Legacy consultancy models assume that visibility requires ubiquitous household smart meter data lakes and heavy Advanced Distribution Management System (ADMS) software overhauls. Modern, hardware-agnostic cellular IoT transformer monitors decouple grid telemetry from legacy software constraints. Distributors can achieve high-density visibility over their distribution substations for low thousands of dollars per zone—invalidating the multi-million-dollar CAPEX barriers cited in sector pushbacks.
2. **The Distribution Substation is the mandatory bridge.** Over 90% of Distributed Energy Resources (DERs)—including solar PV, EV chargers, and residential batteries—connect at the LV level. Thermal overloads and upper-limit voltage excursions bind at the local 400V transformer long before the upstream 11kV/33kV HV feeder hits its design rating. If the Authority permits EDBs to publish top-down HV headroom maps while leaving the underlying LV transformers unmonitored, the market will broadcast "false positive" hosting capacity signals.
3. **The 500kVA statutory threshold creates a blindspot.** We strongly challenge the proposed drafting in Clause 6.3(2)(de)(ii), which restricts capacity reporting strictly to transformers *"500 kVA and above."* As SUPA Energy highlighted in their submission, commercial distributed generation operates well below this threshold (down to 10kW). Retaining a 500kVA floor legally blinds access seekers to the exact physical infrastructure where New Zealand's rapid electrification is occurring.

Nexbe is sympathetic to the engineering burdens highlighted by distributors like Wellington Electricity and Waipā Networks. We also agree with ENA that blunt regulatory force will result in compliance-driven spend rather than genuine consumer benefit.

However, our message to both the Authority and the distribution sector is one of partnership: the solution to the EDBs' data gap already exists.

Distributors do not need to fight peer MEPs for household consumption data, nor do they need to manually stitch together 20,000 static GIS spreadsheets. Instrumenting the distribution substation provides the ground-truth aggregation data required to power dynamic HV models automatically.

Please find attached our detailed cross-submission comments formatted to the Authority's Appendix B Submission Form. This document contains no confidential information and may be published in full on the Authority's website.

Consistent with proposed Clause 6.3A, Nexbe requests to be consulted during the upcoming drafting of the Technical Specifications.

Nga mihi nui,

Richard Oswald

Chief Commercial Officer
Nexbe Limited

Appendix B: Submission form (Cross-Submission)

Improving information on high-voltage network capacity

Submitter: Nexbe Limited

Questions	Comments
Q1. Do you agree with our assessment of the current state of the information and capabilities needed to inform network hosting capacity? If not, please explain why.	**Partially agree.** We agree with the consensus across distributor submissions — including ENA and Waipā Networks—that EDBs possess more mature asset records and SCADA telemetry for their high-voltage (HV) networks than their low-voltage (LV) networks. However, we cross-submit against the assumption that LV constraint modelling is technically out of reach. As WEL Networks explicitly submitted: *"the largest hosting capacity issues for most consumers sit at LV level, where the majority of ICPs connect and where voltage rise and phase clustering are often the material constraints."* Furthermore, Vector noted a major operational barrier: they *"still do not have full access to smart meter data across our network."* Nexbe's technical position is that distributors do not need 100% household smart meter or NOD data from MEPs to resolve edge capacity. By deploying targeted IoT distribution transformer monitoring (starting at the substation level), EDBs immediately bypass the MEP smart meter access bottleneck, securing real-time thermal, voltage, and export telemetry to empirically inform both LV hosting capacity and upstream HV feeder models.
Q2. Do you agree the issues identified by the Authority are worthy of attention? If not, please explain why.	**Agree.** We support the access-seeker perspectives submitted by SUPA Energy (describing daily *"pre-application blindness"* incurring wasted engineering and design costs) and Meridian Energy (requiring transparent locational signals to support the Government's goal of 10,000 public EV chargers by 2030).

	However, because the vast majority of DERs connect at the LV grid edge, solving HV visibility in isolation treats only half of the system architecture.
Q3. Do you agree with our assessment that now is the time to regulate for network visibility? If not, when do you consider would be the right time?	**Agree.** Now is the time to establish a baseline. However, we echo the strong procedural warnings raised by ENA, Network Tasman and Westpower regarding regulatory sequencing. Mandating fixed compliance deadlines before the supporting technical specifications are written risks locking EDBs into expensive interim IT architectures that face subsequent rework.
Q4. Do you agree with our assessment of the outcomes that network visibility supports? If not, why not?	**Agree.** We endorse the Authority's targeted outcomes and agree with ERGANZ that visibility supports competition and efficient investment. However, these outcomes fail in practice if an access seeker screens an HV capacity map, identifies 2 MW of apparent feeder headroom, and deploys capital—only to have their connection rejected or curtailed post-application because the unmonitored LV distribution transformer supplying the site is thermally overloaded.
Q5. Do you consider the proposed amendments to Part 6 of the Code would promote the Authority's statutory objective? If not, why not?	**Partially agree.** While advancing long-term consumer benefit (Section 15), publishing top-down HV capacity maps in isolation risks allocative inefficiency by broadcasting incomplete capacity signals to DER developers.
Q6. Are there any matters you believe are missing from the proposed Code amendment? Please specify.	**Yes.** As WEL Networks explicitly submitted: *"The proposal does not adequately address distributor access to LV metering data, particularly voltage performance data… which makes it difficult to calculate distribution substation and feeder capacity with confidence."* To resolve this, the Code amendment must bridge the HV-LV divide. We recommend inserting a statutory mechanism requiring EDBs to feed empirical LV distribution substation (transformer) loading and

	voltage telemetry into their published HV hosting capacity methodologies.
Q7. Is the indicative timeframe for implementing the proposed Code amendment likely to be adequate? If not, please provide information supporting a different timeframe, including identifying cost savings from a later implementation date.	**Adequate, *subject to architecture*.** Wellington Electricity outlined the immense complexity of their meshed network, noting that continuous along-circuit reporting would force them to manually assign capacity and reliability metrics across *"20,000 GIS objects."* Cellular IoT transformer monitoring bypasses legacy ADMS/SCADA IT integration bottlenecks. Hardware grid-edge monitors deploy in under an hour and communicate via secure cloud APIs, allowing EDBs to validate constrained feeder models by September 2027 without waiting for multi-year GIS grid software overhauls.
Q8. What are your views on the proposed approach where detailed information about the data sets captured within the definition of network capacity information would be contained in technical specifications?	**Support.** We agree with Transpower (citing EPRI research with which we are familiar) and Deakin University (CSPER) that hosting capacity is an evolving, complex process rather than a single static number. Holding data definitions within technical specifications allows the Authority to iteratively adapt telemetry schemas as distribution substation monitoring matures.
Q9. Do you consider that the proposal to develop network visibility specifications in consultation with interested parties would be effective? If not, why not?	**Agree.** We support the cross-submissions of peer vendors GridQube and EA Technology. Vendor participation is vital to ground the specifications in practical, commercial reality and prevent over-specification.
Q10. Is the proposed timeframe for developing the specifications likely to be sufficient?	**Yes.** Six months is sufficient provided the initial scope remains tightly focused on core capacity and topology.

Q11. Do you agree with the proposal to start with high-voltage network visibility? If not, please share your perspectives on where best to start.

Strongly Disagree with HV in isolation. We cross-submit directly against EDB proposals seeking to restrict visibility strictly to 11kV+ assets.

1. **The Physics:** Upper-limit voltage excursions from residential rooftop solar export, or dynamic thermal overload from clustered EV chargers, bind at the 400V LV transformer long before the upstream 11kV feeder hits its thermal rating.

2. **Access Seeker Demand:** SUPA Energy explicitly requested *"clear hosting capacity data for transformers, extended from the current 500kVA threshold downward to cover the commercial DG range we operate in (10kW–5MW)."*

3. **International Precedent:** EA Technology submitted that in the UK, *"86% of Distribution networks have built low voltage network capacity models without Smart meter data,"* unlocking *"3-minute self-service connection quotes"* and slashing feeder design costs by 90%.

The most efficient starting point is the physical bridge between the edge and the grid: the LV Distribution Substation (Transformer). Monitoring at this nexus directly resolves localized LV constraints while providing the empirical bottom-up aggregation telemetry required to validate HV models.

To ensure transparency when calculating high-voltage hosting capacity for 22 kV and 11 kV distribution networks in New Zealand, both high-voltage and low-voltage voltage regulation must be considered.

High-voltage network voltage is influenced by transformer tap changer operation, feeder conductor impedance, network loading, and distributed generation. Variations in high-voltage network voltage are transferred directly to the low-voltage network through distribution transformers, which typically operate on fixed tap settings and therefore reflect changes occurring on the upstream network.

Low-voltage network design must accommodate these high-voltage voltage variations while maintaining customer voltages within the statutory limits of 230 V +10% / -6% supply. Consequently, any increase or decrease in high-voltage network voltage reduces the available voltage margin on the low-voltage network.

Because high-voltage and low-voltage voltage regulation are inherently interconnected, accurate hosting capacity assessment requires measurement and analysis of both networks. Low-voltage monitoring systems, combined with appropriate algorithms, can separate and quantify the effects of localised low-voltage loading and generation from aggregated high-voltage voltage fluctuations.

This provides a more accurate representation of total network voltage regulation and enables more reliable determination of available hosting capacity.

Q12. Do you agree with the assumptions the Authority has made? Why/Why not?

Disagree.

1. Westpower submitted that complying with the proposed digital regime would cost their small regional network *"over $400,000 initially,"* while Powerco highlighted the substantive cost sitting in big data processing pipelines.

The Authority's cost assumptions reflect an all-or-nothing IT approach. Targeted edge transformer IoT monitoring captures the vast majority of network constraint value at a fraction of the cost of legacy SCADA grid extensions or full ADMS software replacements.

2. We support the concerns raised by Orion, Powerco, and Vector regarding the Authority's assumption that five-year capacity forecasts will be accurate or useful.

One critical point not fully addressed in the consultation paper is that EDB forecasting is heavily reliant on the timing of new connection applications that are known within the system, but have not yet reached financial close. These applications must remain commercially confidential from the general public.

This is particularly evident with grid-scale solar and large load connections, where available network capacity and allocation are carefully managed based on the timing of requests. If an EDB publishes a 5-year forecast, they must either omit these pre-financial-close projects (rendering the map dangerously misleading) or include them (breaching commercial confidentiality).

Because speculative HV forecasts are so easily distorted, the Authority should instead prioritize real-time and near-term empirical visibility at the LV edge.

Q13. Have we correctly identified the benefits of network visibility?

Agree. However, as Counties Energy noted regarding their live capacity map, customer benefits cannot materialize if access seekers are given high-level map visibility that lacks actionable site-specific validity.

Q14. Do you have any information that might help quantify the value of these benefits? If so, please provide this information.

Real-time thermal loading visibility at the LV transformer level allows distributors to safely operate assets closer to their true dynamic ratings. This enables EDBs to defer physical substation transformer upgrades by 5 to 10 years via non-network solutions (flexibility), saving tens of millions in capital expenditure across a standard network footprint.

Q15. Have we correctly identified the costs of network visibility?

Partially agree. As Wellington Electricity illustrated, traditional top-down visibility requires amalgamating five separate data silos (*SCADA, GIS, PowerFactory, Load Forecasts, and Reliability records*). The IT overhead of hard-linking topological single-line diagrams to geospatial GIS objects is severe.

Lightweight edge IoT sensors decouple grid data collection from legacy IT software constraints.

Q16. Do you have any information that might help quantify the costs? If so, please provide this information.

Hardware-agnostic cellular edge monitors deploy without grid interruptions and stream directly to cloud platforms via standard APIs.

Distributors can instrument high-priority distribution transformers for thousands of dollars per zone, radically undercutting legacy consultancy cost estimates.

Q17. Have we correctly identified the regulatory overlaps?	**Agree.** We support Powerco and ENA in noting that duplicate reporting (e.g., quarterly vs. annual SAIDI/SAIFI under different calculation rules) creates unnecessary compliance overhead.
Q18. Do you agree with our assessment that there is a net benefit notwithstanding any regulatory overlap? If not, why not?	**Agree.** Uniform statutory rules are required to eliminate market information asymmetry.
Q19. Do you have any information that might help quantify the costs and benefits associated with the regularly overlap? If so, please provide this information.	No comment.
Q20. Do you agree that the Authority should consider reducing the regulatory overlap as the proposed specifications are developed?	**Agree.** As an MEP, we support **Tenco's** submission that private embedded networks operating behind a parent ICP should be carved out of duplicative public reporting obligations.
Q21. Do you agree with our assessment that there will be net benefit from the proposed amendments? If not, why not?	**Agree, *subject to edge accuracy*.** A positive net benefit is achieved only if speculative connection friction is genuinely reduced. If an access seeker relies on an HV map to site a commercial battery but faces immediate export curtailment due to an unmapped LV transformer constraint, the net economic benefit is destroyed.
Q22. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	**Disagree.** We advocate for a targeted hybrid option: *"Mandate HV network visibility, explicitly validated by representative LV Distribution Transformer monitoring."* This fulfils the statutory objective of efficient industry operation (Section 15) far more effectively than top-down HV estimates.

Q23. Do you agree the Authority's proposed amendments comply with section 32 of the Electricity Industry Act?	**Agree.**
Q24. Do you have any comments on the drafting of the proposed amendment?	**Two significant drafting concerns:** 1. Clause 6.3(2)(de)(ii) - 500kVA Threshold: The draft restricts transformer capacity disclosures strictly to units *"500 kVA and above."* We strongly recommend against this threshold. As SUPA Energy highlighted, commercial distributed generation operates well below this threshold down to 10kW. Setting the statutory floor at 500kVA blinds the market to the physical distribution substations where electrification is happening. We recommend amending this clause to capture all distribution substations or requiring a statistically representative monitored sample across sub-500kVA asset classes. 2. Clause 6.3(3B) - Five-year Forecasts: As cross-referenced in Q12 above, we agree with Orion, Powerco, and WEL Networks that the five-year forecast requirement is flawed. Publishing maps based on highly volatile, commercially confidential connection queues will result in large, misleading data swings for access seekers. We recommend removing the 5-year forecast requirement and replacing it with a requirement to publish empirical, current-state dynamic capacity validated by grid-edge telemetry.
Please indicate if you wish to be consulted during the development of the technical specifications supporting the proposed Code amendment.	**Yes.** Nexbe requests inclusion in the technical working groups to contribute practical expertise on integrating distribution transformer IoT telemetry into EDB high-voltage capacity methodologies.