19 August 2025

Electricity Authority
PO Box 10041
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By E- Mail: fsr@ea.govt.nz

Re: The future operation of New Zealand's power system – Consultation paper

Counties Energy Limited (**CEL**) welcomes the Electricity Authority's (**EA's**) continued exploration of future system operation and agrees that increasing distribution-level complexity, driven by distributed energy resource (**DER**) uptake, requires a coordinated and fit-for-purpose operating model.

We support the paper's intent to progress the Distribution System Operator (**DSO**) conversation and provide the following key positions:

- **Definition of DSO Functions**: We broadly agree with the definitions provided but recommend greater clarity in distinguishing DSO roles from those of Flexibility Service Providers (**FSPs**) and Transmission System Operation (**TSO**), particularly regarding customer consent, data visibility, and real-time DER operation. We also emphasise the evolving role of the Distribution Network Owner (**DNO**), which already undertakes many operational functions proposed for DSOs.

- **Focus on Distribution-Level Operation**: We support the shift in focus toward system operation at the distribution level. However, flexibility markets must evolve with safeguards in place to avoid equity issues, market distortion, and long-term inefficiencies. Flexibility should be seen as a transitional tool, not a permanent alternative to reinforcement.

- **Critical Gaps Identified**: The paper could more strongly highlight challenges around cybersecurity, DER interoperability, forecasting capability, equitable access to network hosting capacity, and the absence of standardised integration protocols between DSOs, FSPs, and the TSO.

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- **Problem Definition and Framing**: We agree that the problem lies in the need for a more coordinated system operation framework, but highlight that interoperability, consumer equity, and trust must be considered core enablers alongside coordination.
- **Learnings from Overseas**: Australia and the UK provide valuable lessons around retaining local DSO responsibility, enabling Dynamic Operating Envelopes (DOEs), enforcing interoperability, and establishing clear roles and standards. These should inform the New Zealand approach.
- **Preferred Model – Hybrid**: CEL supports the Hybrid model. It leverages existing network investment and capability, enables local innovation, and provides a platform for standardised national coordination. This model is best positioned to support both operational and market development needs over time.

In conclusion, CEL endorses a Hybrid DSO approach rooted in local networks and supported by common standards, secure data-sharing protocols, and equitable market design. We are committed to working collaboratively with the EA and sector partners to co-design the frameworks necessary for a more distributed, digital, and decarbonised future energy system.

We have attached our detailed responses to the consultation questions in the Annex below. We're happy to engage with the EA further on any content of our submission. Please contact Astad Kapadia [redacted] Head of DSO Strategy, if you have any questions.

Yours sincerely,

Astad Kapadia

Head of DSO Strategy

Counties Energy

Annex – Response to questions

Questions	CEL comments
The case for an emergency reserve scheme in New Zealand	
1. Do you agree with the above explanation of the distribution system operator (DSO) role/ entity, and the explanation of the distribution system operation (DSO) functions that one or more DSO entities would be required to perform?	CEL agrees in principle with the explanation provided. We believe that DSO(s) are functions responsible for the planning and operation of DER services – such as real-time DER visibility, DER integration, and flexibility services facilitation. However, we do believe that functions, such as real-time network visibility, constraint calculation/mapping, network data visibility and availability, are important, but better suited to the role of a smarter/evolving DNO. A key foundational aspect of a DSO's role is to co-ordinate with TSO and doing this in a standardised manner. As a starting point a DSO and TSO should co-ordinate and share data on DER visibility, historic DER consumption/injection, forecasted DER injection/consumption and ability to respond to emergency events. Additionally, we recommend that the demarcation between DSO(s) and Flexibility Service Providers is also added to these definitions. This would be especially beneficial to topics such as "consumer engagement and consent management" as a core FSP function that is made visible to local DSOs. As DER coordination increasingly involves automated decisions about consumer assets, it is essential that DSOs and FSPs are trusted to act transparently, securely, and in the best interest of consumers. Like retailers/traders being required to comply with mandatory Customer Care Guidelines.
2. Do you think we are correct that the themes we identified in submissions to the initial consultation paper mean we should focus mostly on	Yes. CEL agrees the focus should now shift to distribution-level system operation. With accelerating uptake of distributed energy resources, electrification of transport (although slowed in recent years), and growing consumer participation, the majority of

system operation at the distribution level, and on the new functions required for effective distribution system operation?	operational challenges and opportunities now emerge within distribution networks. These include voltage and thermal constraint management, congestion forecasting, and localised flexibility enablement. Focusing on these new functions is necessary to ensure reliability, equity, and system efficiency. CEL would like to comment on three further points: • *Direct customer payments and flexibility incentives*: From the perspective of a distribution network owner and operator (DNO/DSO), the increasing use of payments, discounts, or incentives to customers and flexibility service providers raises important questions around market maturity, fairness, and long-term efficiency. While financial incentives for demand curtailment or flexibility services can be effective tools in a mature and competitive market, in the near term they risk distorting price signals. For example, FSPs may inflate their baseline forecasts and withhold flexibility until prices reach a desired threshold — effectively gaming the system. In an immature market with limited competition — often dominated by a few large aggregators—this behaviour can drive up costs and deliver poor value to consumers. A key concern is the source of funding for these payments. In many cases, the cost of paying for flexibility is socialised across all consumers, meaning those without distributed energy resources — often lower-income households — may effectively subsidise those who can afford to participate. This raises a fundamental equity issue. Balancing incentives for flexibility with fairness across the customer base requires careful policy and regulatory consideration. • *Market fairness and equity*: Without sufficient transparency and competition, emerging flexibility markets risk reinforcing existing disparities between consumers who can afford DERs and those who

	cannot. This creates the potential for a two-tier energy system in which the benefits of flexibility are disproportionately captured by more affluent or technologically enabled customers. The DER market (supported by the DSO locally) must be designed with explicit attention to equity and fairness, ensuring that flexibility markets support system-wide efficiency and deliver benefits to all customers, not just those participating directly. • *Requirement to reinforce*: The value of flexibility to a distributor is designed to be temporary and is both time-bound and closely tied to specific network constraints and timings. Flexibility can provide a cost-effective alternative to traditional reinforcement — such as line or transformer upgrades — but only up to a point. Examples in both a residential and commercial & industrial context are provided below: **Residential development:** In a residential subdivision where a distribution transformer has a capacity of 100kVA and a peak demand of 70kVA, that supplies 40 customers. Introducing just 5 x 7kVA EV Chargers that operate during peak hours would create a need to reinforce. A DSO can work with local FSPs and their customers to signal those EV Chargers to reduce consumption during peak to a minimum charging rate of 3kVA (plug in wall socket) which allows for 5 additional (10 total) EV Chargers to connect to the network without requiring network reinforcement. But as soon as the 11th customer wants to install an EV Charger, that transformer must be upgraded. The time before that 11th customer is seen on the network could be 1 year or 5 years or 40 years, but in essence the DSO and DNO can only defer that expenditure till that 11th customer connects. There are also other nuances around every customer enlisting with a FSP and every FSP enlisting with its local DSO, which are assumed to be true for this

	scenario, but practically may not exist, lowering that threshold further from 11 to a much lower number, without regulatory mandate. **Commercial/industrial development:** Similarly, for a commercial connection of a 150kVA public EV Charger to a 500kVA distribution transformer which has a peak demand of 400kVA only 10% of the time. A flexible connection can be offered to the public EV Charging provider by the local DSO and DNO under an agreement that the EV Charger capacity is throttled 10% of the time to 100kVA when dynamically signalled, and this is to be accepted by the public EV Charger operator. But within 3 years say that the operator will be experiencing an uptake of the technology for which the 10% of the time throttling is no longer suitable. In this case the flexible connection can only be offered for 3 years, post which a traditional reinforcement is unavoidable. As demonstrated above, once the ongoing cost of procuring flexibility exceeds the cost of the time value of money of deferral associated with the capital works and the capacity available after use of flexibility, investment in traditional infrastructure becomes more economical. This tipping point — the reinforcement threshold — must be clearly communicated to both FSPs and customers. Transparency around the duration and value of flexibility signals is essential to avoid misleading long-term expectations, to guide efficient investment decisions, and to preserve trust in the market. Flexibility should be seen as a transitional tool, not a permanent substitute for essential network investment. It is worth noting that there are also instances where flexibility solutions are not practical. These three points require attention if flexibility is to be seen as a sustainable solution.

3. Do you think we have accurately covered the main changes to the distribution system in this section? If not, what have we missed or where have we gone wrong?	CEL agrees that the consultation paper identifies many of the key changes impacting the distribution system. However, there are several important areas that warrant more explicit consideration: 1. Consumer engagement and informed consent: As distributed energy resources become more integrated with network operations and system services, consumer trust and understanding will be crucial to enable participation. Customers need clear, accessible information about how their devices are being used and what value they receive in return — especially in automated or third-party controlled contexts. 2. Cybersecurity and operational technology risk: The growing reliance on digital control systems, data exchange, and remote device management introduces significant cyber-resilience challenges. These risks must be treated as core operational issues, not just compliance or IT matters. The paper could more strongly emphasise the need for coordinated standards and investment in cybersecurity capabilities across the distribution sector. 3. Forecasting, modelling, and uncertainty management: The distribution system increasingly requires the use of probabilistic and deterministic forecasting tools to manage variable load and generation. These forecasting capabilities underpin efficient flexibility procurement, network planning, and real-time operation. Their importance is understated in the current framing. 4. Interoperability and smart DER enablement: Many DERs are being installed today without adequate foresight for future participation in flexibility markets. Ensuring that DERs are interoperable, smart-enabled, and capable of integrating with future DSO and FSP systems "out of the box" is critical. Otherwise, unlocking their value may

	require costly retrofits or truck rolls in the future—an outcome that risks customer disengagement. 5. Equitable access to hosting capacity: As DER penetration increases, distribution networks must develop fair and transparent methods for allocating available capacity — especially where it becomes constrained. This is particularly important to avoid 'first mover' advantages and to ensure that all customers have a reasonable opportunity to invest in DERs and participate in future markets. 6. Standardised integration between FSPs and DSOs: At present, there is no common integration standard for how flexibility service provider (**FSP**) virtual power plant (**VPP**) platforms interact with DSO distributed energy resource management systems (**DERMS**). This creates technical and cost barriers that can inhibit market development and slow innovation. Accelerating the development of national or industry-level integration protocols should be a priority, especially those adopted from lessons learnt in the Australian markets, given many OEMs selling in the Australian market tend to sell in New Zealand the same products and services. 7. Standardised integration between Transmission System Operators (**TSOs**) and DSOs: Similar to point #6 there's no common integration standard between TSOs and DSOs. This is required to unlock planning and operational benefits for both local and national use of flexibility.
4. Do you agree with how we have defined the problem, as the need for a more coordinated framework of integrated system operation?	CEL broadly agrees with the EA's problem definition, particularly the need for a more coordinated and integrated framework for system operation across transmission and distribution levels. However, we believe the framing could be strengthened by more explicitly acknowledging the following dimensions: • Distribution-level complexity is accelerating: As DER uptake increases, so too does the operational complexity at the distribution level. This includes

	increased volatility, two-way power flows, localised constraints, and more frequent requirement for network visibility and control. Coordination must reflect this reality—both technically and institutionally—so that system-wide outcomes are not limited by lowest-common-denominator capability. • Coordination alone is not enough—interoperability and integration are essential: Without standardised integration protocols between TSOs, DSOs, FSPs, and DERs (e.g. VPP platforms and DERMS), even a well-coordinated framework will struggle to deliver effective system operation. The problem is not just who does what — but how well systems can interact across organisations, sectors and platforms. This technical interoperability challenge should be treated as a core enabler. • Trust, fairness, and equity must be foundational: Any integrated operational framework must consider how benefits and costs are shared across participants—particularly given concerns about DER affordability, gaming behaviour, and cross-subsidisation. Without safeguards, early adopters and large FSPs could capture disproportionate value at the expense of the wider consumer base. The framework must embed fairness and transparency from the outset. • Temporal value of flexibility must be made explicit: The problem definition should reflect that flexibility is often a transitional measure to defer, rather than avoid, reinforcement. Customers and FSPs must be informed of the finite nature of these value streams to avoid misinformed long-term investment behaviours.
5. In your view, what aspects of the Australian and British	From Australia:

deliberations around DSO models are relevant to New Zealand?	• The use of dynamic operating envelopes (**DOEs**) and distributed control trials provide practical insights into near-term DER coordination. • DNSPs retaining core DSO responsibilities has allowed for pragmatic, locally driven innovation. • DSOs enforcing interoperability to tap into more network capacity • DSOs providing a product/services catalogue based on flexibility firmness From the UK: • The functional separation of the Electricity System Operator (**ESO**) and DSOs provides clarity on responsibilities and supports independent flexibility procurement. • Ofgem's regulatory approach to incentivising DSO capability development and flexibility procurement can offer a model for future incentives in NZ. In both jurisdictions, investment in digital platforms, data standards, and open access has underpinned successful coordination efforts. NZ should prioritise similar enablers.
6. What do you think about the direction of research conducted in New Zealand by bodies such as the ENA, NEG and SIDG on the challenges of preparing to perform DSO functions?	CEL acknowledges and supports the work undertaken to date by industry groups such as the Electricity Networks Aotearoa (**ENA**), Northern Energy Group (**NEG**), and South Island Distribution Group (**SIDG**) in exploring the challenges and pathways toward DSO functionality in Aotearoa New Zealand. These initiatives have helped elevate awareness of the technical, commercial, and institutional shifts required to enable effective distribution system operation. However, we believe further work is needed to accelerate progress in several key areas: • Greater focus on implementation pathways and readiness: While high-level frameworks and concept exploration have been valuable, there is a growing need to shift toward actionable roadmaps and operational readiness. This includes the

	development of practical standards, roles and responsibilities, and interoperability requirements that DSOs, FSPs, and DER owners can begin to adopt today. • Emphasis on market equity, consumer outcomes, and trust: Research should more explicitly address the implications of DSO development on customer equity—particularly for those without access to DERs. As highlighted in our earlier responses, the risk of reinforcing existing inequities through poorly designed incentive structures or opaque market arrangements must be addressed through inclusive policy and design principles. • Stronger alignment on interoperability and system integration: A core challenge in transitioning to a functional DSO environment is ensuring that digital platforms, DERs, and operational systems can integrate effectively across the ecosystem. Research and pilot programmes should prioritise the development and adoption of open standards for system-to-system integration between FSP VPPs, DSOs (via DERMS), and TSOs. This is essential to enable scalable, competitive flexibility markets. • Clarifying the finite value of flexibility in distribution planning: Existing work could place greater emphasis on the fact that flexibility is not a permanent alternative to network investment. The integration of planning and operational functions must reflect the temporary nature of flexibility value and incorporate mechanisms to transparently communicate reinforcement thresholds to the market.
7. What is your view about the need for an independent DSO (iDSO)? Should we consider an iDSO now as an option to perform all DSO functions, or a subset of functions related to market facilitation? Or can	CEL does not support the establishment of an independent DSO (iDSO) at this time. Electricity distribution businesses (EDBs) are already actively developing and delivering many of the core capabilities required for effective DSO functionality. Introducing a centralised iDSO now would risk unnecessary duplication, introduce coordination challenges, and

that decision wait until the market for flexibility services is more developed?	likely result in increased cost and delays to delivery. Furthermore, the integration costs would be very high as all DNOs systems and processes are not standardised and customisation adds significant cost at this level. The DSO journey is best seen as an evolution—one that is already underway and largely enabled by digital platforms, services, and systems. Much like how EDBs procure SCADA, ADMS, or enterprise asset management platforms (e.g. Maximo), DSO functionality can be deployed through a combination of in-house capabilities and third-party software-as-a-service (**SaaS**) or platform-as-a-service (**PaaS**) models. This approach supports innovation, flexibility, and local accountability while still enabling common standards and system-wide coordination. That said, as flexibility markets mature and expand, and become commercially viable, there may be a future case for a more neutral or independent entity to perform **specific market-facilitating functions**, such as: • Enabling market transparency and price discovery, • Ensuring compliance with market protocols, • Managing shared data infrastructure or governance frameworks. However, the value, scope, and structure of such a body should only be considered once participation, competition, and market scale are more fully understood. Prematurely centralising these functions risks stalling innovation and reducing the ability of distributors to respond to localised network needs. In summary, we support continuing with a DSO model anchored within existing distribution businesses, complemented by common platforms, standards, and — potentially over time — a focused facilitation layer if warranted by market maturity.

8. What do you think about the three DSO models proposed by the EA?	The three models offer a useful spectrum; are evidence based and are similar international evaluations have been conducted by other markets.
9. Do you prefer one model over the others?	Yes. CEL supports the Hybrid model. It enables existing network capability to be leveraged, accelerates readiness, and allows functions to be delegated or centralised where necessary. National-level coordination of standards, visibility frameworks, and flexibility procurement rules will complement local network operational delivery.
10. Given the hybrid model can take several forms, what do you think would be the best allocation of DSO functions between the TSO and one or more distributors as DSOs?	CEL believes that it has provided feedback on this question as part of its engagement in the Power Innovation Pathway (**PiP**) process. If there are any specific questions beyond the information shared as part of the process, CEL is willing to clarify as required.
11. How would you rank the DSO models in terms of enabling the process of price discovery in the market for flexibility services to approach the wholesale market ideal of security-constrained economic dispatch?	1. Hybrid 2. Total DSO 3. iDSO 4. Total TSO