The future operation of New Zealand’s power system

Consultation paper: Issues and high-level options

24 June 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to future-proofing New Zealand's power system, ensuring it remains secure and resilient so consumers can benefit from reliable electricity supply for years to come. To achieve this, we must understand and tackle the challenges and opportunities of an evolving energy landscape and an increasingly electrified economy.

We have identified key indicators within the sector that could impact the future of New Zealand's power system. The future security and resilience programme prioritises work based on these indicators to maximise capabilities of a modern and innovative energy sector. Our focus is on delivering changes that support the sector's evolution at the least cost to consumers.

A key workstream under the future security and resilience programme is the future of system operation (FSO) of the New Zealand power system. As the power system becomes more complex and decentralised over the next decade, we need to ensure it can support the integration of more variable and intermittent generation resources, as well as an increase in bi-directional electricity flows. More consumers are expected to become involved in their energy choices and be able to participate in the operation of the power system.

In February 2024, we released a discussion paper seeking feedback on several potential issues that could impact on future system operation. We received 53 submissions, and three key themes emerged highlighting the need for:

1. **Greater incentives for consumer engagement:** consumer preferences and behaviours are an important driver of change; however, consumers will only engage if they see clear benefits and find it easy to participate in the power system. Engaging consumer interest and providing incentives for their participation in the power system are essential to unlocking demand-side flexibility. This will in turn address some of the challenges brought on by variable and intermittent renewable generation connecting to the power system.
2. **More coordination in system operation:** a more decentralised power system introduces greater operational complexity from the interaction of multiple generation and load resources at all system levels, from transmission right through to low voltage distribution. Improved coordination of system operation at the distribution level entails better use of consumer-owned distributed energy resources (DER). Consumers (households and businesses) are increasingly investing in DER such as solar PV and batteries which allows them to generate and store their own electricity, giving them the flexibility to use it when needed or feed it back into the local network. This empowers consumers to take a more active role in managing their electricity use and contributing to the operation and stability of the power system.
3. **Clarity of the future architecture of the distribution sector:** this includes new capabilities, functions, and roles of participants and other parties to ensure consumers benefit from their investment in and use of DER.

To respond to these needs, a coordinated framework for integrated power system operation will be required. This will enable consumers to connect and operate their DER and potentially reduce system cost across the value stack. In this way, the Authority can empower individual consumers and communities to have more control over their energy systems.

The future operation of the distribution system is challenging

This consultation paper looks at the capabilities and functions needed for distribution system operation in the future.

Several distributors are exploring and developing their capabilities to perform new functions needed to improve coordination and thereby achieve flexibility of both demand and supply in the power system. Flexibility is needed to compensate for the increasingly variable and intermittent nature of renewable energy sources, especially wind and solar generation.

> ***"The electricity sector needs time to develop the new capabilities, practices and processes to ensure flexibility is ready when it is needed in the future to help avoid inefficient investments."*** – FlexForum Plan, 2022

In this paper we acknowledge the multiple ongoing Authority workstreams aimed at ensuring greater coordination of power system operation, including the network visibility data project, the measures to increase demand-side flexibility, and an Energy Competition Task Force proposal that would require distributors to pay a rebate when consumers supply electricity at peak times.

Our proposal

We are putting forward three alternative distribution system operation (DSO) models for consideration. These models differ in how they allocate certain functions, particularly those related to the real-time dispatch of grid-based resources and DER. The coordination of these functions varies between Transpower in its role as the transmission system operator (TSO) and (one or more) distributors acting as (one or more) distribution system operators (DSOs).

Efficient allocation of these functions—between the TSO, one or more distributors, and/or DER aggregators—will facilitate more effective coordination of DER for the benefit of their owners, including consumers.

The three DSO models we are putting forward are:

- **Model 1: Total TSO model**
  The TSO is solely responsible for coordinating real-time dispatch. Distributors have a limited role in this model. Effectively, the TSO is the DSO.
- **Model 2: Hybrid model**
  Coordination of real-time dispatch is shared between the TSO and one or more distributors-as-DSOs. Both the TSO and distributor/s have significant DSO responsibilities.
- **Model 3: Total DSO model**
  One or more distributors-as-DSOs are responsible for coordinating real-time dispatch. The transmission system plays a supporting role in this model, but effectively one or more distributors are the DSOs.

We considered a fourth option of creating or appointing an independent distribution system operator (the iDSO model) for real-time network operation functions, however, this has been tentatively excluded on likely cost and complexity considerations.

The Authority acknowledges an iDSO might be required to facilitate a subset of DSO functions related to distribution market mechanisms and ensure neutrality if there are misaligned interests for distributors performing distribution system operation services. We do not consider this would be the case in the next few years however, as all three model options contemplate potential measures to address any misalignment of interests should these arise.

Arguably, New Zealand is already effectively operating a hybrid model for real-time distribution network operations. Transpower as the system operator manages flexibility services required for the wholesale market, while distributors are encouraged through regulation to procure and dispatch non-network solutions or flexibility services to delay or substitute for the strengthening of their distribution networks. DER aggregators decide which market(s) to offer flexibility services into and can do so through a distributor or the TSO.

The Authority prefers the hybrid model, as this is likely an efficient and reasonably affordable model and would likely facilitate the uptake and connection of DER for the benefit of consumers. However, we are considering all proposed models equally and would like to encourage all interested people and parties to submit their feedback on this consultation.

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1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this paper is to consult with interested parties on options for the future operating model of New Zealand's power system, particularly the distribution component of the power system.

1.2. While we cannot predict how power system operation will evolve in the coming years, we can proactively prepare for a system that supports New Zealand's move to a more electrified economy. This will enable a smoother transition to a decentralised power system, leading to better outcomes for all consumers. We want it to be easier for households and businesses to derive value from their consumer-owned energy resources (CER) and distributed energy resources (DER).

1.3. Consistent with our statutory objectives, the Authority is particularly interested in:

(a) the efficiency and reliability of New Zealand's power system operation in the future

(b) how changes to power system operation in the future might affect consumers and industry participants

(c) how best to enable consumers to become 'prosumers' via their CER, in a way that promotes a secure and resilient power system.

1.4. The paper considers the expected capabilities and functions needed from electricity distributors, the system operator, aggregators, and/or various third parties. It outlines three high-level options for defining the functions of one or more distribution system operators (DSOs), considers who might perform these functions, and whether the impacts on consumer benefits might differ across the options.

1.5. The Authority prefers one of these high-level options, but we would like the options discussed in the paper to be the basis for further engagement between ourselves and stakeholders. We encourage input and views from all stakeholders.

How to make a submission

1.6. Submissions are due by 5pm on 19 August 2025. The eight-week consultation period is designed to encourage detailed feedback, from a broad range of voices, on the options put forward in the paper to help collectively shape the future of the power system.

1.7. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to fsr@ea.govt.nz with "*Consultation Paper - The future operation of New Zealand's power system – Issues and high-level options*" in the subject line.

1.8. If you cannot send your submission electronically, please contact the Authority (fsr@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.9. Please note the Authority intends to publish all submissions we receive. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part, and

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.10. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.11. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.12. Please deliver your submission by 5pm on Tuesday 19 August 2025.

1.13. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority (fsr@ea.govt.nz or 04 460 8860) if you do not receive electronic acknowledgement of your submission within two business days.

2. Introduction

2.1. The Authority has received feedback from industry stakeholders that it should prioritise investigating challenges and opportunities for power system operation in New Zealand, given the ongoing and anticipated changes affecting New Zealand's power system.

2.2. Effective and expert coordination of the power system will be crucial to maintaining reliability, at lowest cost, for consumers. The future security and resilience of the power system is a key priority as New Zealand transitions to a more electrified economy. With its independent and industry-wide perspective, the Authority is well positioned to facilitate a review of future power system operation, working closely with industry stakeholders.

2.3. This paper is part of the Authority's multi-year Future Security and Resilience (FSR) work programme. The FSR programme seeks to ensure New Zealand's power system (at both the transmission and distribution levels) remains secure and resilient as the economy electrifies.

2.4. By 'power system' we mean all components of the New Zealand electricity system underpinning the New Zealand electricity market, including generation, transmission, distribution, storage and consumption (load) assets.

2.5. The FSR programme is focussed on how New Zealand's power system operates in real time, or close to real time, to balance electricity supply and demand on a continuous basis, to supply consumers with electricity at an appropriate level of quality.

The purpose and scope of the Future System Operation workstream

2.6. The future operating structure of New Zealand's power system is one of the key priorities in the FSR programme. We are looking at this under the Future System Operation (FSO) workstream, the purpose of which is to:

(a) identify any challenges and/or opportunities with the current arrangements for power system operation in New Zealand that may arise given expected changes to the electricity industry

(b) identify what, if any, regulatory arrangements administered by the Authority would address challenges with, or enable opportunities for, power system operation in New Zealand, for the long-term benefit of consumers.

2.7. The Authority has initiated the FSO workstream in response to:

(a) stakeholder feedback on the need for a coordinated approach to the evolution of power system operation over the coming decades

(b) the need to see power system operation in New Zealand incorporating lessons learned from relevant international developments.

The changing nature of New Zealand's power system

2.8. New Zealand's power system is undergoing a significant transformation. The electricity sector is experiencing major shifts in both the generation supply mix and in electricity demand. These changes are being driven by the emergence of new technologies, the decreasing costs of certain technologies, and decarbonisation driven by the implementation of economy-wide climate change policies. For example, energy storage systems (ESS), in particular (electrochemical) battery energy storage systems (BESS) of significant capacity, are increasingly being paired with solar farms. In that way, energy production can be split between solar and BESS and timed to match consumption needs while enhancing resilience to contingent events.[1]

Reliability, Security and Resilience

We use these terms frequently – here's what they mean.

Reliability refers to both the continuity of electricity supply (ie, the rate and duration of electricity outages, including due to insufficient fuel for electricity generation), and the quality of electricity supply (eg, the frequency and voltage of electricity).

Security refers to the ability of the power system to withstand adverse events, ensuring a steady and stable network that delivers generation to where it is needed (ie, significant adverse events do not cause electricity outages).

Resilience refers to the ability to identify and mitigate high-impact, low probability threats to the power system quickly and efficiently, to minimise the damage to infrastructure and support services, while enabling a quick recovery and restoration of the power system to a stable state.

2.9. The power system is evolving from a system dominated by large machine-based electrically synchronous power stations located remotely from load centres to a decentralised system of technologies, capable of power generation and storage, smart grid formation, automatic voltage regulation, uninterruptible power supply backup, fault ride-through, black start, and more.

2.10. We expect most new electricity generated in New Zealand to come from renewable energy sources, especially wind and solar, which are variable and/or intermittent by nature. Generation from renewable energy sources will reduce emissions in other sectors, such as transportation and industrial processes, but its variability and intermittency mean that either demand must be more flexible, or more firming generation must be sourced, if the power system is to remain balanced.

2.11. The scale of change required means it is important to balance the competing goals of the energy trilemma: security, equity and sustainability. A critical challenge will be delivering a level of security, reliability and quality of electricity supply that reflects consumers' preferences and minimises total costs.

[1] See for example Meridian Energy: Ruakaka Energy Park

Electrification will reshape the electricity industry

2.12. New Zealand is committed to transitioning to a more electrified economy as part of its broader climate change goals. This transition involves a substantial shift from fossil fuels to renewable energy sources. Given the high renewable energy composition of electricity generation in New Zealand, key sectors, such as transport and process heat, are expected to be highly electrified over coming years and decades.

2.13. By 2050, electricity demand is expected to increase by at least 35 per cent (from 2023 levels) and possibly much higher.[2] Annual electricity demand is projected to reach 62 terawatt-hours (TWh), supplying about half of New Zealand's total energy needs. Peak demand is also projected to grow significantly, reaching nearly 11 gigawatts (GW) by 2050.

2.14. This transition will fundamentally change New Zealand's electricity sector. As the economy becomes more electrified, addressing peak demand fluctuations, managing increased variability and intermittency of energy sources, and ensuring the power system remains secure, reliable and resilient, will become significantly more challenging.

2.15. The Government Policy Statement on Electricity underscores the need for a secure, resilient, and efficient power system that supports decarbonisation while ensuring consumer benefits.[3]

2.16. Despite the challenges, the transition to an electrified economy presents significant opportunities. The power system is expected to be decarbonised and digitised, and also decentralised and democratised, with DER aggregators (also known as flexibility service providers or flexibility traders) facilitating the development of flexibility services. Note the Authority recently published a Green Paper seeking feedback on the opportunities and challenges of a more decentralised electricity system.[4]

Decarbonisation, decentralisation, democratisation and digitisation are all trends influencing the power system.

Decarbonisation refers to the process of reducing carbon emissions from energy production and consumption. It involves transitioning to low-carbon energy sources like solar, wind, and hydro power, and improving energy efficiency in all sectors.

Decentralisation involves shifting energy generation from large power plants to smaller, more localised sources, including distributed energy resources (e.g., rooftop solar panels).

Democratisation as a consequence of decentralisation, refers to the process of empowering individual consumers and communities to have more control over their energy systems. Communities can generate their own energy, participate in energy markets, and benefit from the transition to a clean energy economy.

2 MBIE, *Electricity Demand and Generation Scenarios: Results summary*, July 2024.

3 Statement of Government Policy to the Electricity Authority, October 2024.

4 Working together to ensure our electricity system meets the future needs of all New Zealanders.

Digitisation refers to the use of digital technologies to improve power system operation. For example, developing smart grids to manage power flows, using digital tools to monitor energy consumption, and using digital platforms for electricity trading.

2.17. Flexibility will come from multiple sources, including demand-side flexibility, energy storage systems, and enhanced (smart) electricity network management systems. A flexible power system should reduce the costs of electrification and energy to households and other consumers, as it compensates for the variable and intermittent nature of new renewable electricity supply.

DER aggregators and flexibility services

DER aggregators or flexibility service providers or flexibility traders (note we mainly use the term DER aggregators in this paper) manage and coordinate multiple DER such as rooftop solar panels, energy storage systems and electric vehicles.

DER aggregation involves combining multiple individual DERs into a single entity or portfolio, via virtual power plants (VPPs), energy management systems, or advanced software platforms. By aggregating DERs, their combined energy can be coordinated for more efficient operation and used to provide services in energy markets such as arbitrage, ancillary services, or the wholesale energy markets. This enables DER owners – including consumers – to benefit from additional revenue, thereby increasing the value of DERs and the incentive to invest in DERs.

In some international jurisdictions, DER aggregation is regulated and can include rules and frameworks that facilitate and govern the participation of aggregated DERs in energy markets. Regulations might cover compensation mechanisms, technical requirements, market access and operational rules for aggregators.

Flexibility services are transactions for a certain amount of electricity (or the suspension of electrical load) from one or more DERs for a certain period, triggered by an external price or other agreed signal, in exchange for a consideration such as a price, discount, or rebate. Consumers might control their DER or contract a retailer, an aggregator or a distributor to do so on their behalf.

Consumer participation will bring significant benefits

2.18. As these changes take place, the role of consumers in the electricity market will become increasingly important. Advances in technology and the growing availability of DER, such as rooftop solar, battery energy storage systems (BESS), and electric vehicles (EVs), are enabling consumers to actively participate in electricity generation, storage, and flexibility services.

2.19. Consumers (households and businesses) are increasingly investing in DER. DER allows consumers to generate and store their own energy, giving them the flexibility to use it when needed or feed it back into the local network, which they will be inclined to do if retailers offer them attractive buyback rates. This empowers consumers to take a more active role in managing their electricity use and contributing to the operation and stability of the power system.

Distributed Energy Resources (DER) refer to small-scale electricity generation, storage, and management technologies that are located close to where energy is consumed. These include rooftop solar photovoltaic panels, home and commercial battery energy storage systems (including EVs), and other on-site renewable energy sources. DER enables consumers to generate, store, and manage their own electricity, reducing reliance on the traditional power grid.

Consumer-owned Energy Resources (CER) are a subset of DER that specifically emphasise the role of consumers in energy generation, storage, and demand response. CER includes technologies that allow households and businesses to actively participate in the electricity market, such as smart appliances, rooftop solar photovoltaic, EV chargers, and energy management systems.

For clarity, this report uses the term DER to refer to both Distributed Energy Resources and Consumer Energy Resources.

2.20. While some consumers may prefer to manage their own DER, aggregators can simplify the management burden for consumers. By aggregating multiple DER, aggregators can scale up these resources to more effectively participate in the wholesale electricity market, including as a provider of ancillary services, for the benefit of consumers as well as power system operation. Again, consumer participation depends on aggregators making attractive offers to consumers.

2.21. Flexibility in the power system has widespread benefits for all New Zealanders. Flexibility can help smooth peak periods of demand and thereby offset or defer the need for transmission and distribution network upgrades, and investment in new electricity generation. Importantly, this reduces costs that would otherwise flow through to consumers.

2.22. Consumer investment in DER can potentially address all three elements of the energy trilemma[5] by:

(a) enhancing **sustainability** through providing flexibility that balances intermittent generation sources, benefiting all network users

(b) improving the **security** and **resilience** of energy supply for regions, neighbourhoods and for individual consumers

(c) contributing to **equity** by improving affordability and accessibility for consumers by enabling partial self-supply, shifting consumption to times when prices are lower, and even exporting surplus power to consumers suffering hardship.

2.23. For consumers to fully benefit from controllable DER and flexibility services, the role of electricity distributors and distribution pricing becomes increasingly important, as does the role of aggregators to develop value propositions for consumers that own DER. A well-designed approach to distribution network investment, operation and

5 World Energy Trilemma Framework

pricing will support a power system that is increasingly decarbonised, decentralised, digitised, and democratised.

Distributors have an important role to play in supporting decentralisation

2.24. Distributors have a major role to play in unlocking the potential of DER and flexibility services. Most behind-the-meter DER are owned by consumers who, with advice from experienced installers, determine how much generating capacity to install, where to install it, whether to include battery storage and how to operate it to suit their own needs first but allowing for export of excess energy to the network. It is possible that misalignment of DER owners' and network operators' interests may limit the broader benefits these resources can provide to the power system.

2.25. New Zealand has 29 electricity distributors that connect the transmission grid with consumers, smaller electricity networks and generators. These 29 distributors are responsible for owning, planning, building, maintaining, and operating their respective distribution networks.

2.26. New Zealand's energy transition will place changing demands on distribution networks. Operation of the new, decentralised power system with increasing consumer participation will be complex. At the distribution level, DER must connect to the networks and coordinate with other DER if consumers are to benefit from more active participation in the power system.

2.27. As DER and the need for flexibility services continue to grow, the management of this market will be key to maintaining a stable, efficient, and resilient power system.

New functions are needed for effective distribution system operation

2.28. The increase of DER connecting to distribution networks will pose increasing challenges for distribution system operators. Distribution networks can be considered in three voltage ranges:

(a) low voltage (LV) – 400 volts 3-phase and 230 volts 1-phase

(b) distribution voltage – 11,000 volts (11 kV), usually 3-phase

(c) sub-transmission voltage – 33,000 volts (33kV) and above, 3-phase.

2.29. As more DER connects at these levels, their impacts aggregate through progressively higher voltages towards the transmission system.

2.30. Resource decentralisation will perhaps be better thought of as a flat interconnected power system, as compared with the top-down model we use when describing transmission and distribution networks today.

2.31. In this future model, network operator actions can impact not only adjacent networks but also the entire power system, making collaboration and coordination essential for efficient power system operators and planners. As more DERs are added to networks, assumptions about demand diversity and predominant power flows must be updated.

2.32. With more dynamic and unpredictable power flows, network operators will need greater flexibility to efficiently balance supply and demand, manage congestion, and maintain voltage stability.

2.33. The roles of distribution system operators (DSOs) and the transmission system operator (TSO), and how they interact, need to be redefined to increase the integration of DER within the power system. More complexity is added when one considers the interactions required between the distribution network and the layers beneath it, which can be optimised in their own right: between the distribution network and the microgrid gate; between that and the home or building fuse; and between that and the HEMS / BEMS (home/ building energy management systems) within the building.

2.34. Industry participants at the distribution level recognise the challenges and opportunities of the power system transition in progress and the need to prepare for the coming changes. Some distributors have begun developing the capability to perform new DSO functions.

2.35. When considering the power system's transition, the Authority is mindful of its main statutory objective to promote competition, reliability and efficiency for the long-term benefit of consumers. We wish to see DSO arrangements that are consistent with this statutory objective.

What exactly is a distribution system operator (DSO)?

2.36. An EPRI publication[6] included some useful definitions of the DSO and the capabilities required of parties performing the functions of the DSO role. Here we reproduce two DSO definitions – the first is a definition written for the Australian Energy Market Operator (AEMO):

DSO refers to the entity that is responsible for planning and operational functions associated with coordinating DER services for distribution networks and/or DER participation in wholesale markets in coordination with the TSO, aggregators, and other relevant parties.

2.37. The second is the definition used by UK regulator Ofgem:[7]

Distribution system operation is a set of functions and services that need to happen to run a smart electricity distribution network. This does not focus on a single party as an operator but recognises roles for a range of parties to deliver DSO. The core DSO functions include:

(a) Real-time distribution network operations – facilitate efficient dispatch of distribution flexibility services; manage local supply and demand to maintain distribution network stability; identify congestion and address constraints on distribution networks; promote network operational visibility and data availability

(b) Distribution market mechanisms – value, incentivise, and procure energy, capacity, flexibility, and ancillary services from DER for the purpose of distribution network operation; embed simple, fair and transparent rules and

6 EPRI 2023 Technical Update: Enabling DER Service in Distribution Operations.

7 Ofgem Position paper on Distribution System Operation.

processes for procuring distribution flexibility services; provide accurate, user-friendly and comprehensive market information

(c) *Integrated distribution system planning – ensure efficient investment in distribution networks to meet future market needs; plan efficiently in the context of uncertainty, taking account of whole system outcomes, and promote the availability of planning data.*

2.38. An aspect of the DSO role is that the way it is defined sets out various functions, and whoever takes on those functions might need to acquire new capabilities to perform those functions. This is partly because some functions will be new and partly because investment is required to perform some functions. For example, more data is required to monitor network conditions and to determine the existence, location and status of DER, and communication devices must comply with standards and protocols to allow interoperability, data transfers and communication.

2.39. Some DSO functions demand knowledge of the technical potential of DER to contribute to grid stability and reliability. For example, identifying the grid services that can be provided by DER, such as frequency regulation, voltage support and active power control.

Q1. 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?

2.40. There are also challenges in procuring grid services from DER owing to their decentralised and intermittent nature. Coordinating and dispatching these services requires sophisticated control systems to optimise DER operation and ensure they can respond to grid needs. This can be performed by a Distributed Energy Resources Management System (DERMS). There is a role for the use of ‘indirect dispatch’, for example, the use of dynamic operating envelopes (DOEs)[8] in distribution system operation to nudge decisions about the use of DER in the right direction.

8 A dynamic operating envelope or DOE defines the safe operating limits for power import or export at a specific connection point, and these limits can vary over time and location. This allows one or more DER to safely connect without compromising the stability or security of the network.

3. Themes from the submissions on our discussion paper

3.1. In February 2024 the Authority published a consultation paper on the key drivers for change and the challenges and opportunities with power system operation in New Zealand over the coming decade and beyond.

3.2. We received 53 submissions on the consultation paper, which are available on the Authority's website.[9] The common themes in the submissions were:

- the importance of consumer behaviour and participation in markets supported by the power system
- the need for more coordination of power system operation
- the need for more clarity on the future capabilities and functions of DSOs.

3.3. In this section we briefly explore each of these themes. Appendix B notes and responds to several other matters raised in submissions that are being covered in other Authority workstreams.

The importance of consumer behaviour and participation

3.4. In examining the critical factors driving change in New Zealand's power system, several submitters emphasised that consumer preferences and behavioural changes should be recognised as a key driver of change. We agree that consumers are critical to decentralisation of the power system. However, the increased participation and engagement of widely dispersed consumers, particularly residential and small business consumers, cannot be taken for granted; the right conditions and incentives are required.

3.5. We might expect consumers to participate more actively in the future power system, but they will only do so if they see clear benefits for themselves and if it is easy for them to participate.

3.6. Many consumers may prefer to engage passively, relying on default settings and/or using agents to engage on their behalf. The development and availability of pricing or remote-control options, will be critical in this regard, as will the development and packaging of flexibility opportunities for consumers to get the most out of their DER.[10]

3.7. Distributors, retailers and aggregators should consider what incentives will help to engage consumers, and how they will react to offerings that involve discounts, payments or other benefits.

3.8. The objective of the FSO workstream is to put consumers at the core of the power system. Our vision is for consumers to have choices in accessing the energy they need now, and in the future, to ensure they and New Zealand prosper. Importantly, this includes self-providing some or most of their electricity by investing in DER and

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9 See Future operation of New Zealand's power system/Submissions.

10 An example is the collaboration between Orion, Wellington Electricity and Octopus over Resi-Flex.

thereby becoming more resilient to events beyond their control. They may also decide to participate, whether actively or passively, in markets related to the power system if they see additional benefits.

The need for more coordination of power system operation

3.9. Another common theme that emerged from submissions was that the increasing complexity of the power system implies a need for more coordination amongst resource owners and operators. Several submissions noted the challenges around coordination, and some of the key data issues that will need to be resolved, so that DER can be coordinated more effectively to facilitate effective and efficient power system operation. Key data issues include:

- Data collection: how, by whom and for whom
- Data granularity, frequency and aggregation
- Data accessibility, pricing, storage, protection and sharing.

3.10. These three issues appear to be prerequisites for the step-up in coordination that will be required in the future operation of the power system.

3.11. More data is needed to improve the visibility of DER across distribution networks. In addition, wider adoption of devices (such as inverters) and their compliance with standards and communication protocols will better facilitate the interoperability and controllability of these devices.

3.12. Finally, managing congestion on distribution networks will be a key aspect of coordinating DER. There will likely need to be a mechanism for allocating distribution network capacity as part of DER coordination. This will be an issue to a greater or lesser degree at all voltage levels across distribution networks as DER connections proliferate. Distributors suggest using DOEs for this purpose, a key DSO function that entails a regularly updated assessment of network headroom and some neutral form of allocation of that spare capacity to users in the event of network congestion.

The future capabilities and functions of DSOs is a key issue

3.13. Several submissions discussed the roles of distributors that look to evolve from distribution network operators (DNOs) only, to providing DSO services as well. Over time, a DSO role would likely require significant investment in automation, communications with smart meters, real-time systems, managing big data, and data analytics. These capabilities would give a DSO better visibility of the distribution network and its connected DER. This, in turn, would make it easier to determine the hosting capacity of the distributor's network, DOEs[11] for DER, and the allocation of network capacity between DER aggregators (and the DSO itself, for any DSO-owned or controlled DER).

[11] While a dynamic operating envelope (DOE) provides real-time operational limits to manage CER and DER, a hosting capacity assessment determines the overall potential for integrating CER and DER into the network.

3.14. As distribution networks evolve, so will ideas about the role of distributors or third parties in developing new capabilities related to DSO functions. Submissions pointed to the need for more clarity on the future architecture of the distribution system, including what the functions of DSO would be, whether distributors or third parties could or should perform some or all DSO functions, and how many DSOs there should be.

3.15. The timing of when DSO capabilities are needed may be highly variable between distributors, depending on factors such as size, location (urban or rural), DER uptake and network capacity utilisation. Smaller or more remote distributors might prefer to purchase DSO functions from another distributor or a third party (the shared services approach).

3.16. These factors may influence when distributors decide to invest in DSO services, such as accessing the data required to improve their visibility of DER connections and network conditions and constraints. The DSO functions are not just to address the impact of DER on a constrained network: they can be used to deploy flexibility instead of asset renewal and to bolster resilience.

3.17. Some submissions noted concerns around the potential for misaligned interests for distributors participating in the market for flexibility services, particularly as distributors undertaking a DSO role would need to determine DOEs that allocate network capacity to participants in the flexibility service market. Distributors as DSOs might also want to run or facilitate one or more flexibility services platforms, and their independence could be compromised if they were to be suppliers in that market as well as market operators.

3.18. Participating in flexibility markets is not considered a DSO function. If distributors do provide flexibility services, this should be considered as them playing the role of an aggregator rather than a DSO function. Measures may be needed in such instances of misaligned interests to ensure the neutrality of a distributor towards other aggregators.

Q2. Do you think we are correct that the themes we identified in submissions to the initial consultation paper mean we should focus mostly on system operation at the distribution level, and on the new functions required for effective distribution system operation?

4 Changes affecting distribution system operation

4.1. In this section we talk about how the increasing share of renewable energy generation is creating the need for more demand-side flexibility, and how this is impacting on distribution networks. Increasing network congestion is likely as the market for flexibility services develops, unless DER are better coordinated and orchestrated using new DSO functions.

Demand-side flexibility is becoming critical

4.2. The electrification of transport and industrial process heat will require significant new investments in renewable generation, especially in geothermal, wind, and solar, complemented by new investment in energy storage such as battery energy storage systems (BESS).

4.3. The variable and intermittent nature of wind and solar generation means that weather will constantly impact local real-time electricity supply, requiring that electricity demand is significantly more flexible in future and that energy storage must be available to play a role in providing a controllable energy resource.

4.4. Equally there are opportunities for electricity demand to be shifted towards periods when solar and wind generation are abundant, which can be valuable for charging batteries and EVs, heating water cylinders, and running other appliances when tariffs or other signals can be adjusted to encourage consumption.

4.5. Therefore, demand-side flexibility (DSF) is required to compensate for the variable and intermittent nature of new wind and solar generation.

4.6. DSF can also help to defer or avoid network upgrades and reduce the aggregate peak demand for electricity, contributing to supply security and efficient investment.

4.7. The importance of ensuring sufficient DSF is stressed in the recent Government Policy Statement on Electricity:[12]

> *Demand-side flexibility (‘DSF’) is where consumers shift their demand in time or alter their total demand. Like generation, DSF is an important resource for matching supply and demand. It is also a tool for managing price risk. If demand-side response is available in the market at a lower price, it should displace generation as the preferred source for meeting additional demand.*
>
> *Efficient DSF will deliver benefits for both consumers (lower bills) and for the system as a whole (more resilience).*

4.8. To stimulate DSF at the distribution level, in December 2023 the Market Development Advisory Group (MDAG)[13] in its recommendation 5 (price-driven secure distribution dispatch) said the Authority should develop an efficient form of security constrained economic dispatch (SCED) on distribution networks for the purpose of integrating DSF and other sources of DER into the wholesale market.

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12 Government Policy Statement to the Electricity Authority, p6.

13 Price discovery in a renewables-based electricity system.

This followed an MDAG recommendation to investigate extending locational marginal pricing (LMP) into distribution networks. MDAG considered that could be a way of efficiently managing the dynamic needs of distribution networks for DSF and stated:[14]

> *The reason that conflict potentially arises between wholesale DSF and distribution network DSF (or more broadly DER) is that the locational scarcity signal implied by congestion in a distribution network is not signalled to the market model, and therefore cannot be optimised (and least cost dispatch achieved) from a whole-of-system perspective.*

4.9. While MDAG acknowledged in its 2023 report the complexity of the task involved, it pointed to the advances in computing power, algorithms, and communications technology which have occurred since the implementation of SCED on the national grid in 1996. Also, SCED would not have to be implemented all at once for all distribution networks. Options could be considered to bring select DER/DSF into the national wholesale market, potentially on a regional basis and/or distribution network “depth” basis (eg, sub-transmission down to zone substations only). In this way, SCED could expand incrementally to enable price discovery on a needs basis.

The market for flexibility services is developing

4.10. The uses of DER to save or earn money are known as flexibility services, transacted in one or more flexibility services markets. Some uses of DER might be imputed rather than transacted, such as using rooftop solar as self-supply. The market for flexibility services is still relatively undeveloped but is likely to grow in step with the uptake of DER and as the visibility of the distribution networks improves.

4.11. Consumer behaviour in respect of rooftop solar is likely somewhat diversified in time and location, and relatively predictable provided the weather is known by time of day and season. Consumers derive value from self-consumption by optimising any battery storage they may have installed alongside the solar, and their time of consumption where convenient to do so, particularly of their large household loads, such as charging EVs. The aim is to optimally reduce their electricity bills. Consumers with solar with or without battery can also sell their surplus energy to their retailer for additional value.

4.12. In Australia, most DER comprises passive rooftop solar installations. In New Zealand, active DER is more common, especially hot water cylinders and now, increasingly, household batteries and EV batteries. These DER can be coordinated by distributors, aggregators or retailers. Coordinated behaviour cannot be predicted based on weather and time of day or season. Active DER provides additional potential sources of value to customers via participating in the wholesale market. Aggregators and retailers can help consumers to use their active DER to participate in the markets for energy, and ancillary services such as frequency keeping and instantaneous reserve.

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14 Price discovery in a renewables-based electricity system – Library of options.

4.13. Consumers can also conclude bilateral agreements outside of the market, with distributors, aggregators or retailers, to sell DER services including network support for frequency keeping, voltage control or to defer network investment, or peer-to-peer trading where MTR (multiple trading relationships) is enabled.

4.14. Very few consumers have DER that are interactive, although many systems are equipped with active management capabilities. Therefore, as the market for flexibility services develops, active DER have huge potential for earning additional revenue for consumers. However, it's important for aggregators, retailers and distributors to anticipate pitfalls of simplistic time-of-use plans that might cause 'herding' of EV charging, spiking consumption when a cheaper tariff kicks in.

Distribution network challenges

4.15. As they grow with increasing complexity, the issues associated with connecting more DER to distribution networks can be considered in three voltage ranges:

(a) low voltage (LV) – 400 volts 3-phase and 230 volts 1-phase

(b) distribution voltage – 11,000 volts (11 kV), usually 3-phase

(c) sub-transmission voltage – 33,000 volts (33kV) and above, 3-phase.

4.16. Connections of distribution networks to Transpower's grid range from 11-110 kV.

4.17. Low voltage networks are widespread across the country. Many consumer metering installations for premises connected to LV networks have been upgraded over recent decades with advanced metering infrastructure, or 'smart meters.' Advanced metering installations have remote meter reading capabilities and, in many cases, some capability for data capture and storage.

4.18. Installing DER 'behind the meter' at an ICP usually requires replacement of the existing meter with a meter capable of separately measuring and recording electricity imported to and exported from the premises. In some cases, a relatively modern meter may be able to be reprogrammed to provide import and export metering functionality.

4.19. Potentially, the coordination and some control of LV-connected DER in networks that are not yet congested, can be automated to a degree. This would rely on DER in such network segments incorporating modern inverters that comply with recent standards to regulate local voltage and implement robust anti-islanding protection.

4.20. Low levels of monitoring and consequently low visibility of the operating status of the local network may be all that's required if the network in question has adequate spare capacity.

4.21. While some distributors have invested in fault detection and logging systems that access data from smart meters, ICP-level problems such as power interruptions and poor power quality are usually 'phoned in' by affected consumers to either the consumer's retailer or directly to the local distributor's service centre.

4.22. As the number of similar DER installations on a single LV feeder grows, such as within a suburban setting, the (approximate) aggregate impact of all the generated quantities and loads will be visible using smart metering or other network visibility technology. There may also be a need for visibility of DER at a sample of ICPs, as concentrations of DER on the LV network rise, and/or as DER aggregation rises.

4.23. Therefore, as the uptake of DER rises and as DER aggregators become more active, so the LV networks will become more congested and there will be a greater need for more ICPs with advanced meters, to facilitate the coordination and orchestration of DER. However, network congestion will also require the DSO function of using DOEs to ration solar exports (as in Australia), or to allocate import capacity for charging EVs (more likely in New Zealand).

Distribution networks may be congested

4.24. Some of the challenges encountered in operating the higher voltage levels (ie, 11kV and above), such as pockets of network congestion, have already been encountered. Many distributed generation connection projects have been commissioned or are in advanced stages of construction, planning or investigation.

4.25. Distributed generation installations that are large relative to the capacity of the local network, particularly solar, wind and battery energy storage systems, may give rise to local congestion, export constraints and power quality issues. Each case needs power system stability modelling to determine possible congestion or other power quality issues. Solutions need to be developed and negotiated with connecting parties.

4.26. While new distributed generators may seek unrestrained operation that makes maximum use of their intermittent energy resource, network capacity expansion is not always feasible or affordable; a means of managing available export capacity is needed. A robust congestion management policy is required to establish DOEs to manage such export constraints. This is a new and important function that falls within the DSO role, as it requires the allocation of finite capacity between network users.

4.27. Therefore, network operation of higher voltage distribution networks where the presence of distributed generation is causing a degree of congestion, will likely require one or more DSOs providing new coordination services, utilising inputs (resource forecasts, current network status, visibility from SCADA and LV substations aggregated at the feeder level) and possibly coordinating with the TSO.

4.28. On the subject of addressing network congestion, MDAG developed recommendations aimed at strengthening the operation of the wholesale electricity market, given the increase in demand being met from new, mostly intermittent, generation.[15] Some of the recommendations relate to the management of increasing levels of congestion in distribution networks caused by connecting a pipeline of large variable and intermittent distributed generation projects—especially where these projects are large relative to the capacity of the distribution circuits and substations they seek to connect to.

15 Price discovery in a renewables-based electricity system.

4.29. Relevant MDAG recommendations seek to ensure that aggregators are made Code participants, and that distribution network capacity is reflected in wholesale demand-side flexibility (DSF) dispatch as an interim step. A longer-term solution recommended by MDAG, as mentioned above, is recommendation 5, to develop design and trial tools to enable security constrained economic dispatch on the distribution network (consistent with existing transmission-level security constrained economic dispatch). The Authority plans to do further work to investigate and scope this recommendation in the second half of 2025/26.

Active versus passive DER

4.30. Local network challenges can involve either passive DER or active DER. Describing DER as either passive or active does to some extent reflect how controllable they are, although even active DER are only controllable to the extent they can be kept in a desired state rather than changed to that state. Nevertheless, the following distinction can be made:

(a) Passive DER is mainly rooftop solar, which is significantly more prevalent in Australia than it is in New Zealand. Local network voltages can rise to very high levels if there is significant export of excess generation to the local network without adequate voltage control provided by the solar/battery inverter. Undiversified exports from rooftop solar systems can also exceed the peak current carrying capacity of the local network infrastructure, potentially overloading circuits and distribution transformers.[16]

(b) Active/controllable DER includes batteries, EV charging (on the verge of becoming bidirectional), and hot water load management. Once sufficient aggregations of these resource types accumulate, their active control may cause similar problems to rooftop solar at a local level, but the impacts can be more severe due to the potentially high ramp rates these resources are capable of. For example, when large aggregations of batteries change their operating mode from full charge to full discharge, high reverse power flows will be triggered that may exceed the local network capacity and possibly exceed distribution fuse ratings. Such a scenario could play out with active resources responding to a spike in a 5-minute real time dispatch signal.

Active versus passive consumers

4.31. As mentioned above, many submissions said the consumer is a key driver for change in the power system. Consumer behaviour is changing, as more consumers invest in rooftop solar with a battery, EVs and other forms of DER. Some consumers are more engaged with their role as a distributed generator than others. Some engaged consumers might be early adopters of consumer electronics and home automation, while others might be concerned with protecting the environment. Yet others might be attracted by the potential financial benefits of DER.

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[16] AEMO/ENA: Open Energy Networks consultation.

4.32. On the other hand, there remain many consumers who have not invested in DER, for several reasons. Importantly, many consumers cannot afford the price of purchasing DER. Those who can, may not be convinced the benefits outweigh the costs, or perhaps they think the payoff is not fast enough, or that the costs of DER will fall further, so it is worth waiting. Some houses might not have roofs that can accommodate solar panels, or the roofs might be angled wrongly or be in the shade. Furthermore, renters are unlikely to invest in DER.

4.33. Engaged consumers might be seen as *active* if for example they prefer to decide for themselves when and where to charge their EVs. But other engaged consumers – once they have purchased their DER – might prefer their engagement to be more *passive,* for example simply signing up with a flexibility trader or aggregator, such as a retailer, to let them make the decisions about controlling their DER for them.[17]

4.34. Therefore, although it is important that consumers become more engaged with the power system so that they are more inclined to invest in DER for the right reasons for them, it is also important that there should be easy options available for these consumers to sign up to, so they can benefit from their DER, for example EV charging retail plans. The ease of extracting value from DER will also encourage less-engaged consumers to become more engaged and to invest in DER.

The system operator needs to interact with distribution networks

4.35. We covered the system operator's role earlier in this section, particularly as it relates to its real-time responsibilities.

4.36. The system operator has the following needs:

(a) New 'best practice' forecasting platform/methodologies that take account of weather intermittency at generation locations. This could be a DSO role with regional DSOs responsible for aggregating the impacts of weather intermittency within their areas of responsibility. Possibly a single weather forecasting platform that covers the whole country with outputs shared by the TSO and DSOs for both system-wide and distribution network operational purposes.

(b) New data sources.

(c) Voltage coordination protocols with connected asset owners.

(d) A comprehensive fit for purpose review of ancillary services. As penetration of inverter-based resources (IBR) increases at all levels across the system, system inertia and system strength will reduce.

(e) Coordinated emergency response when managing significant disaggregated DER. DSOs may be able to decide how to disconnect load but will need to coordinate with the TSO to re-liven primary connections.

[17] At the date of writing, one New Zealand electricity retailer had a "no bills for 5 years (with terms and conditions)" product in the retail market, if the customer delegates full control of their battery assets to the retailer. Also, several of the largest retailers are trialling smart hot water management and EV charger management schemes for their customers.

4.37. For its part the system operator has expressed concern that it needs to have standardised interactions with as many DSOs as may exist at distribution level. This encompasses interoperability, which in turn relates to compatibility of devices and inverters with acceptable standards and protocols. It also means the system operator would prefer to be transacting with standardised protocols and flexibility product types across New Zealand. The same need applies to businesses, consumers and aggregators dealing with up to 29 distributors.

Security of supply challenges

4.38. At the system level, passive DER in the form of small-scale DER might not cause disruption for some time yet. However, for active/controllable DER aggregated to the level of a virtual power plant (VPP) or for larger scale solar and wind farms and large-scale BESS, ramp rates can be several hundred megawatts in a very short period, which if changing from charging to discharging could have the same impact as tripping a large power station.

4.39. Such VPP operations, if unscheduled, could make it impossible for the TSO to respond with sufficient reserves or frequency keeping. The TSO would need to rely on information from DSOs as to whether network capacity will allow such VPP offers to be delivered.

4.40. Similarly, there could be large and rapid ramps by aggregated DER (eg, EV chargers responding to time of use tariff periods) which could require an increase in the required frequency control reserves, which increases costs paid by market participants, and these are recovered from consumers.

4.41. Ancillary services will require a comprehensive review to meet these challenges.

Q3. 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?

5 Should the Authority intervene to enhance distribution system operation?

Defining the problem at the distribution level

5.1. In this section we ask whether there is a problem in distribution system operation that requires some intervention by the Authority, or whether that problem would be resolved by sector participants themselves.

5.2. As discussed above, three main themes emerged from submissions on the Authority's February 2024 FSO consultation paper:

(a) The importance of consumer behaviour and participation.

(b) The need for more coordination of system operation.

(c) The need for more clarity around capabilities, roles and functions of distributors and other parties when it comes to the operation of the distribution system.

5.3. Other workstreams are aimed at improving access to data, which should improve coordination of system operation, and facilitate the more efficient use of DER by consumers and others. As explained further in Appendix B there are also workstreams dealing with common quality obligations that will enhance coordination; and the Electricity Engineers Association (EEA) and Energy Efficiency & Conservation Authority (EECA) are working towards implementing inverter and device standards and communications protocols that will enhance interoperability and coordination.

5.4. However, these workstreams that facilitate coordination of system operation can only do so if the power system architecture is optimised, particularly at the distribution level. That is, sector participants and other parties must be given the go-ahead by the Authority to invest in the capabilities they require to perform the new DSO functions that will result in better coordination of system operation at the distribution level.

5.5. Distributors, the TSO and aggregators must be sure that their functions and interactions with each other are consistent and complementary and that there will be no regulatory prohibition once they have already committed resources to improving the coordination of DER.

5.6. Therefore, the Authority's view is that the problem can be defined as the need for a more coordinated framework or architecture of integrated system operation. This should enable consumers to connect and operate their DER, so they are available to consumers for their own use, and potentially to reduce system cost across the value stack, while ensuring network and wider system security.

5.7. Without intervention, there could be inaction and delayed investment in capabilities and functions, and this would slow down the uptake of DER by consumers and delay the expected benefits to consumers of being able to use DER for part of their electricity needs.

Q4. Do you agree with how we have defined the problem, as the need for a more coordinated framework of integrated system operation?

What exactly would the Authority give direction about?

5.8. Implementing a more coordinated framework of integrated system operation would mean allocating the required DSO functions to the TSO and one or more distributors (and/ or third parties) to co-optimise the operation of DER on distribution networks with the operation of grid-connected assets on the transmission system.

5.9. There are several alternative ways of allocating the required functions between the TSO, interested distributors and/ or third parties. These are the so-called DSO models, and in this paper we put forward three alternative DSO models for consultation.

5.10. The models are mainly intended to improve the coordination of distribution system operation. However, distribution system operation involves many different functions and services, as noted earlier in this paper:

(a) Real-time network operations – Facilitate efficient dispatch of distribution flexibility services; manage local supply and demand to maintain distribution network stability; identify congestion and address constraints on distribution networks; promote network operational visibility and data availability.

(b) Distribution market mechanisms – Value, incentivise, and procure energy, capacity, flexibility, and ancillary services from DER for the purpose of distribution network operation; embed simple, fair and transparent rules and processes for procuring distribution flexibility services; provide accurate, user-friendly and comprehensive market information.

(c) Integrated distribution system planning – Ensure efficient investment in distribution networks to meet future market needs; plan efficiently in the context of uncertainty, taking account of whole system outcomes, and promote the availability of planning data

5.11. Note that the choice of a particular DSO model does not necessarily mean all the functions listed above are allocated in the same way between parties, and there could be changes over time. At this point, the choice of model is most important to determine who performs the functions of real-time network operations, as set out in (a) above.

5.12. In addition, the Authority should clarify that participants and other parties in the sector can confidently invest in acquiring the capability to provide DSO functions, whilst avoiding any misalignment of interest for distributors in their various roles.

5.13. However, the flexibility market development functions described in (b) above might initially be performed by one or more distributors-as-DSOs and/or aggregators or independent third parties and only replaced by an independent body if in the longer term it appears the development of the market for flexibility services might require an independent body to facilitate the specification of standardised products and ensure flexibility service market platforms are neutral.

5.14. The development of the flexibility market could be driven by independent businesses offering services such as market platforms. For example, Our Energy in collaboration with Cortexo and EpexSpot recently announced an independent local flexibility market platform, Localflex. This will allow distributors to broadcast their needs to, and procure from, local flexibility service providers.

5.15. There could be a role for assessing how the market for flexibility services is tracking in terms of price discovery and whether it is approaching the level of efficiency that can be achieved in the wholesale market via security constrained economic dispatch.

5.16. Equally, the distribution system planning functions described in (c) might remain the responsibility of all distributors, or move to one or more distributors that become DSOs, or be shared with Transpower or the TSO. In the UK, Ofgem[18] has tasked the recently nationalised, national energy system operator (NESO) to implement regional energy strategic plans (RESPs), which will involve distribution-level network planning functions, in collaboration with distributors, local authorities and other local stakeholders.

5.17. Ofgem has devised a three-part planning process, to achieve coordination at the national and local levels: at the national level, the Strategic Spatial Energy Plan (SSEP) and the Centralised Strategic Network Plan (CSNP), and at distribution level, the RESP. All three plans will be delivered by NESO. Ofgem[19] decided that:

> *'…network companies must align their network planning to the direction of the RESP. We consider this a 'direction-setting' role' and 'the RESP will complement the other strategic plans being developed – SSEP and CSNP – and NESO must ensure there is coherence between the outputs.'*

5.18. Ofgem will also require distributors, in their distribution network operation roles (DNOs), and gas distribution networks (GDNs), to align their investment plans for network capacity with the strategic direction set by the RESPs covering their respective licence areas. Ofgem also expects DNOs to demonstrate alignment with RESPs down to the primary substation level.

5.19. Transpower in its Te Kanapu document[20] has announced its intention to develop a future grid blueprint that anticipates the grid's role in coordination and optimisation across the power system as a whole. Transpower will analyse impacts and opportunities from broader changes in the power system, including the role consumer-owned DER and electric vehicles (vehicle to grid) can play in providing short-duration storage.

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18 Decision on the Regional Energy Strategic Plan Policy Framework.

19 As above, at page 32.

20 Transpower-Te-Kanapu-May-2025.pdf.

6 Different models for allocating DSO functions

6.1. This section considers options around who might develop capabilities and perform the new functions required of the role of distribution system operator (DSO). Options exist across several key decisions:

(a) a spectrum from total transmission system operator (TSO) control on one end of the spectrum, to total DSO control (by distributor/s) at the other end, and then various hybrid options in between, where there is a mix of responsibilities and functions between the TSO and the one or more distributors-as-DSOs

(b) who should perform what DSO functions – the TSO, distributors, aggregators, or independent third parties? There may be efficiency and/or reliability benefits to distributors carrying out some or all the DSO functions. Or it might be more efficient for the TSO to take on the DSO role. This partly depends on who can perform DSO services for least cost, and partly on whether there are concerns about misalignment of interests for distributors (rather than aggregators or other independent parties) taking on the role. If there are misaligned interests for distributors that evolve into DSOs, then a third party could perform the role, or a subset of the role, such as market facilitation services, as was decided in Great Britain

(c) how many DSOs should there be? This comes down to factors such as the cost of duplicating the resources needed to provide DSO services, versus local, network-specific knowledge.

6.2. Next, we note developments in Australia and Great Britain, where distributors are starting to transform into DSOs.

Standardised naming of DSO models

6.3. Given that different terminology has been used in different countries we use the following names for the different DSO models to facilitate comparisons:

- **Total TSO model** – the transmission system operator (TSO) takes on the DSO role
- **Total DSO model** – one or more distributors-as-DSOs take on the role of DSO (in addition to their roles as DNOs – distribution network owners)
- **Hybrid model** – the DSO role is split up somehow between the TSO and one or more distributors-as-DSOs
- **iDSO model** – one or more independent third parties take on the role of DSO/s

International experience

6.4. Though New Zealand faces similar power system operation challenges to those in other countries, we operate a much smaller market than many of our frequent comparators. Unlike larger markets such as Australia and Great Britain, New Zealand might not need to, and/or have the resources to, replicate the required capabilities and functions across all existing distributors. However, note the caveat about the pace of technology change, which could reduce the importance of market size in determining whether DSO services can be performed viably by smaller distributors.

Open Energy Networks (Australia)

6.5. The Open Energy Networks programme[21] brought together AEMO (the Australian Energy Market Operator), DNSPs (we'll refer to DNSPs as 'distributors' to maintain consistency with New Zealand terminology) and wider stakeholders to consider what changes are needed to market frameworks, and network and system operations. The programme developed four high-level DSO models to integrate DER into the power system:[22]

(a) **A total TSO model** (called the Single Integrated Platform or SIP) – with distributors, the TSO (AEMO) would develop a single integrated platform using agreed standard interfaces to support the participation in an integrated, multi-directional market by retailers, aggregators, and VPP (virtual power plant) platform companies. The TSO would then solve local security constraints and support wholesale market entry. Access to the platform would be a one-stop shop that allows participants to participate anywhere without having to develop separate systems or tools to integrate with the various individual distribution platforms. Distributors-as-DSOs would provide details of network constraints to AEMO, which would consider this information in determining the economic dispatch of resources.

(b) **A total DSO model** (called the Two-Step Tiered Platform or TST) – a layered distribution level platform interface operated by the local distribution network and an interface between the distribution network's platform and the TSO (AEMO). Individual distribution networks would design interfaces that best meet their system requirements, and participants would need to communicate directly with the distribution level platform for the local constraint issues, and the distribution network would optimise these resources against local network constraints based on bids from the aggregators servicing the area. Distribution networks would provide an aggregated view per transmission connection point, and AEMO would take this information and consider the overall system security and economic dispatch.

(c) **A hybrid model –** sought to combine the total TSO model and the total DSO model. For example, the total TSO model highlighted a perceived misalignment of interest in terms of the distributors-as-DSOs maintaining a technical operation role as well as a market clearing function, so under the hybrid DSO model the TSO (AEMO) would run a single market platform, but DSOs would remain responsible for operating the distribution networks, accessing the market platform to help resolve distribution constraints and develop an aggregated (unconstrained) bid stack for its region for AEMO to consider in wholesale dispatch. This was so DSOs could help identify a

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21 Open Energy Networks.

22 Assessment of Open Energy Networks Frameworks.

dispatch schedule of DER to minimise network constraints while AEMO could use that information as part of a co-optimised dispatch, considering both the network benefits and market benefits that DER can provide.

(d) **An iDSO model –** a variant of the total DSO model, or TST, whereby an independent party – a DSO that is separate from the TSO (AEMO) and the distributor – would work with the distributor to optimise DER dispatch based on local system constraints provided by the network business. Aggregated bids would be provided to AEMO to include in the larger dispatch.

6.6. Consultancy Baringa was appointed to assess the different models and do a comparative cost-benefit analysis[23] (Baringa also assessed the 'Future Worlds of distribution system operation' developed in Great Britain[24]).

6.7. Baringa found all frameworks could provide benefits of better DER integration of between A$2.5b and A$6.5b from 2019 to 2039, depending on whether there is relatively slower or faster uptake of DER.

6.8. As for costs, Baringa estimated these at between A$2.5b to A$3.5b. The iDSO model was most expensive as it would involve a duplication of responsibilities and subsequent systems and functions across AEMO, IDSOs and distributors. The total TSO model (the SIP) and hybrid DSO model would benefit from economies of scale associated with centralising market-facing functions and the functionality required to optimise dispatch of DER with a single party (AEMO). The total DSO model (the TST) would be relatively higher cost than the total TSO and hybrid DSO models since it would require each distributor to develop new systems and functionality.

6.9. Some further refinement of the hybrid DSO model will be undertaken in 2025 as part of the CER Roadmap,[25] as Australia continues to work on getting the right framework for DSOs. The Baringa assessment noted that the hybrid DSO model would benefit from more detailed definition to ensure that roles and responsibilities are clear, particularly in the dispatch process. Different versions of the hybrid model could take a form closer to the total TSO model or the total DSO model.

Open Networks Programme (United Kingdom)

6.10. The Open Networks programme[26] was an Electricity Networks Association (ENA) strategic initiative between electricity network companies, the Electricity System Operator (ESO), the government, the regulator, and the wider industry to lead the UK's transition to a smart, flexible energy system ready for net zero.

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23 Assessment of Open Energy Networks Frameworks.

24 See Open Networks Future Worlds (2018) and ENA – work programmes.

25 National Consumer Energy Resources Roadmap.

26 ENA – Open Networks.

6.11. In 2018 the ENA released its 'Future Worlds' document, subtitled 'Developing change options to facilitate energy decarbonisation, digitisation and decentralisation'. This document contained several DSO options:[27]

- **Total TSO model** ('World D') – the TSO (ESO) is the counterparty for DER with DSOs informing the TSO of their requirements.
- **Total DSO model** ('World A') – the DSO acts as a neutral market facilitator for DER and provides services on a locational basis to the TSO (National Grid as the Electricity System Operator or ESO).
- **Hybrid model** ('World B') – the TSO (ESO) and DSO work together to efficiently manage networks through coordinated procurement and dispatch of flexibility resource.
- **iDSO model** ('World E') – a new national (or several regional) third parties act as neutral market facilitator/s for DER, providing 'aggregator of aggregators' services to the TSO and DSO as required.

6.12. Baringa[28] produced an impact assessment of these models and assumed that all models would reach the same endpoint by 2050. They found that the models performed differently depending on the speed of uptake of DER. Baringa concluded that the DSO models that would best achieve certain goals were also associated with certain trade-offs, as follows:

- The total TSO model would be the lowest cost to implement and operate.
- The total DSO model and the hybrid model would maximise the decarbonisation of heat and transport, but the hybrid model would be more complex to operate, and both options might require measures to deal with any perceived misalignments of interest.
- The total TSO model and the iDSO model would facilitate market engagement for flexibility traders, but could delay decarbonisaton, as they would take time to implement.
- The hybrid model would require the least structural change, but could lead to more complexity in system operation, more dispersed accountability, and more friction as new coordination processes bed down.
- The iDSO model would likely achieve transparent, fair and neutral markets, but could be less efficient at decision making, as information needs to be sent back and forth to the independent flexibility coordinators.

6.13. In 2019, ahead of Ofgem setting its next package of price controls for electricity distribution companies starting in 2023, Ofgem stated in a DSO position paper[29]

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27 There was also a 'World C' which we do not discuss further as it wasn't a model but rather reflected the impact of related Ofgem reforms of electricity network access arrangements and forward-looking signals for consumers.

28 Future World Impact Assessment.

29 Position paper - Ofgemhttps://www.ofgem.gov.uk/sites/default/files/docs/2019/08/position_paper_on_distribution_system_operation.pdf.

that network companies should manage any real and perceived misalignments of interest, improve whole system coordination, and embed the key enablers needed in the evolving system – a core part of which is gathering and sharing data.

6.14. In 2023, Ofgem decided[30] to appoint Elexon as the neutral market facilitator, to work alongside the other distributors which are transforming themselves into DSOs, guided by objectives set by Ofgem, such as network visibility. Therefore, the DSO model opted for in Great Britain is most like the hybrid model, plus a limited role for an iDSO, in this case an independent body playing the market facilitator role. Market operation will remain with distributors, but they will be guided by Elexon in terms of standardising product offerings, value stacking and primacy rules. Also, distributors that are involved in flexibility services must ring-fence these activities, to alleviate concerns about misalignment of interest.

6.15. Ofgem decided[31] that distributors should remain responsible for real-time operations, ensuring accountability for reliability and safety rests with them. There would be no requirement for DNOs to create legally separate or independent DSOs.

Q5. In your view, what aspects of the Australian and British deliberations around DSO models are relevant to New Zealand?

New Zealand groups are also considering DSO models

6.16. This section summarises recent thinking about the need for DSOs, and ways of thinking about DSO models or enablement modes in New Zealand. Some distributors, either independently or collectively through groups such as Energy Networks Aotearoa (ENA), are exploring different DSO models.[32] Here we discuss the ideas of the ENA, the Northern Energy Group (NEG), the South Island Distribution Group (SIDG) and Counties Energy.

6.17. Then we put forward three DSO models for consultation, based on the main variants considered both here in New Zealand as well as in Australia and Great Britain. We set out the key features of each model and how they might address the issues with existing arrangements. The models are not intended to be too prescriptive (especially the hybrid model, which can take several forms) or exhaustive (we do not consider the iDSO model in depth, but nor do we rule it out).

The ENA's 'Future Networks Forum' (FNF)

6.18. Electricity Networks Aotearoa (the ENA) represents all distributors in New Zealand. The ENA's Future Networks Forum is an ENA project:

> *'… to improve understanding and alignment between EDBs on the capability, roles, functions and industry architecture to enable distributed flexibility. This will*

[30] Decision- Ofgem.

[31] Decision- Ofgem.

[32] See the ENAs Future Networks Forum initiative, "Aligning EDB Capability, Roles, and Functions to Enable Distributed Flexibility".

help to deliver maximum value to electricity consumers and ensure coordination across the electricity sector.'

6.19. The ENA's presentation for an external webinar in 2024 contained the following tasks, or changes to their business-as-usual activities, that distributors might expect by 2035 (edited):

- Calculating dynamic hosting capacity in near real-time and allocating headroom between the parties managing all the different consumer devices (DG, hot water, EV charging, heat pumps, etc)
- Signalling to network users in real-time, and over time, when congestion is increasing or headroom is tightening
- Two-way automated communications between SO and distributor control rooms on Distributed Generation forecasts and the dispatch of flexible resources, across multiple time horizons
- Managing response to grid emergencies, local network emergencies and network switching through automated instructions to aggregators/ flexibility traders
- Building and maintaining portfolios of contracted network support services from aggregators, and dispatching them for services to defer and avoid investment, and manage outages, automatically transacting with them for the services provided
- Providing full self-service experience for customers: e.g. automatically updating network maps showing hosting capacity and connection cost, integration with distributors' systems, and outage information – aligned across distributors
- Designing and operating flexible connection services with major customers, and deploying for mass market
- Full transparency of network operations and service levels for regulators and stakeholder community

6.20. The three models the ENA identified are:

- The total TSO model
- The total DSO model
- A hybrid model.

6.21. However, much of the attention of Stage 1 of the ENA project is on four identified 'DER enablement modes':

(a) Price Mode: Uses pricing signals to incentivise flexibility. It is characterised by using economic incentives to encourage consumers and businesses to modify their electricity usage based on price signals

(b) Contract Mode: Involves flexibility services procured through competitive markets or flexible connection contracts.[33] It highlights the use of contractual arrangements to secure services needed for system flexibility

(c) Utility/Direct Mode: Focuses on direct control by flexibility buyers (eg, hot water load management or ripple control). It emphasises centralised control to manage network operation efficiently and to ensure reliability

(d) Emergency Mode: Activated during system emergencies to maintain network stability. It operates under statutory and technical standards to ensure immediate and effective response to crises.

6.22. As such, the ENA's proposed DSO models are alternative ways of managing the co-existence of these four enablement modes, but in varying proportions as the flexibility services market develops.

6.23. The ENA appointed Baringa to assess the three DSO models discussed in stage 1 ('roles and functions') for the stage 2 ('industry architecture') part of its project and Baringa's qualitative assessment has been published.[34] The Baringa assessment largely favoured the hybrid model. Some of the key points were:

- The hybrid model could enable customer choice by providing a range of local and wholesale market choices. This model could offer the best of both models, with centralised coordination, reliability and local flexibility.
- The hybrid Model could also require the least amount of regulatory change and allow a logical expansion of existing entities' activities into the flexibility space.
- A total TSO model would mean Transpower's existing capability would need to be expanded significantly to cover the local distribution constraints being integrated with wholesale market optimisation.
- A total DSO model would require the TSO/DSO interaction to be clear and transparent, however forcing aggregators/retailers to access all markets via the DSO, and the regulatory change required to aggregate flexibility would pose challenges.
- The ENAs members should agree a robust method for valuing costs and benefits of this system-wide transformation.

The Northern Energy Group (NEG)

6.24. The Northern Energy Group was formed in 2019 and comprises seven consumer-trust owned distributors in the North Island (Top Energy, Northpower, Vector,[35] Counties Energy, Waipā Networks, The Lines Company, and Electra).

[33] Flexible connection contracts allow customers to connect to a network if they agree to a degree of flexibility, which both increases the capacity of the network to accommodate these new connections, and increases demand-side flexibility.

[34] Potential-DSO-models-for-New-Zealand.pdf.

[35] Vector is 75.1% owned by Entrust (local consumer trust), with the balance being listed on the NZX.

6.25. The NEG's work on DSO evolution is summarised in a presentation posted on LinkedIn.[36] In one of the slides, partly reproduced in Figure 1, the DSO sits between the network and the national wholesale markets, and its functions are the dynamic management of capacity and the orchestration of DER (and DER managers).

6.26. The NEG documents support a hybrid model, and it endorses the work of the ENA's Future Networks Forum, which it says is 'aiming to deliver nationally aligned solutions.'

6.27. The DSO functions NEG members are pursuing are:

- Whole system orchestration
- Capacity allocation and management
- Asset and operations management
- Flexible systems and flexible network connections
- Digitalised operations and communications interfaces and standards

6.28. The NEG also provides a list of activities requiring EDB collaboration with regulators and Government decision makers. For each item, we add a brief note explaining any relevant Authority work that is underway.

(a) Ensure statutory regulations for EDBs (e.g. quality and reliability) remain fit-for-purpose in a world with market-based DER management. *(The Authority's Part 8 review of common quality obligations is relevant).*

(b) Establish minimum technology and communication standards to enable smart system management and interaction, and provide the allowances to invest in this capability (and the data required) *(The Authority engages with the EEA and EECA on these standards and protocols).*

(c) Develop – potentially through 'sandboxing' – a framework for the implementation and operationalisation of dynamic capacity management on distribution networks, including principles for how capacity is allocated between system users and the requisite communication protocols *(The Authority's Power Innovation Pathway or PIP programme is potentially suited to this activity).*

(d) Ensure that all parties managing DER on behalf of consumers and investors (DER Managers) have agreed operational protocols with their host networks, formalising the requirement on the DER Manager to manage within the operational limits of the network *(The Authority considers this is already possible without additional regulation).*

(e) Clarify the ability of DSOs to orchestrate the response of DER Managers to system emergencies – from the very local (e.g. car vs pole) to nationwide *(Distributors have begun negotiations with retailers around 'Load Management Protocols' for emergency situations).*

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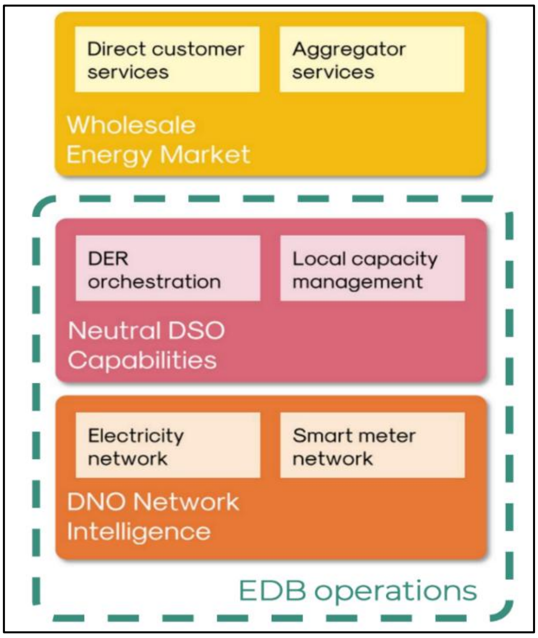
[36] LinkedIn – NEG vision on DSO evolution.

(f) Amend distribution pricing rules to ensure parties who benefit commercially from network capacity fund it. *The Authority released two complementary consultation papers on distribution connection pricing and processes in October 2024.*[37] *The Authority also ran consultations closing on 26 March 2025 on the pricing principles for distributed generation,*[38] *and on the proposed requirement for distributors to pay a rebate when consumers supply electricity at peak times.*[39]

(g) Enable commercial access to network operational data and ensure the minimum level of metering capability necessary to deliver it. *(This is being addressed by the Authority's work on increasing access to affordable network operational data, for improved network visibility).*

Figure 1 NEG depiction of neutral DSO capabilities



6.29. The NEG work identifies actions that require some form of intervention from the Authority. An aspect of the NEG depiction in Figure 1 is its reference to 'neutral' DSO capabilities (the Counties DSO project also refers to 'neutral DSOs'). The reference to neutrality is not explained further in either the NEG or Counties work on DSOs, but the term echoes the Ofgem requirement for distributors to be neutral in their marketing of flexibility services. The term 'neutral' also resonates with the term used in the Authority's draft guidance to distributors involved in the flexibility services market – that they should treat third parties 'even-handedly'.

[37] See Distribution connection pricing proposed Code amendment and Network connections project: stage one amendments.

[38] Distributed Generation Pricing Principles.

[39] Requiring distributors to pay a rebate when consumers supply electricity at peak times.

The Counties DSO project

6.30. Distributor Counties Energy has set out its rationale for embarking on a DSO pilot project (which has now been elaborated on and submitted to the Authority under its PIP programme).

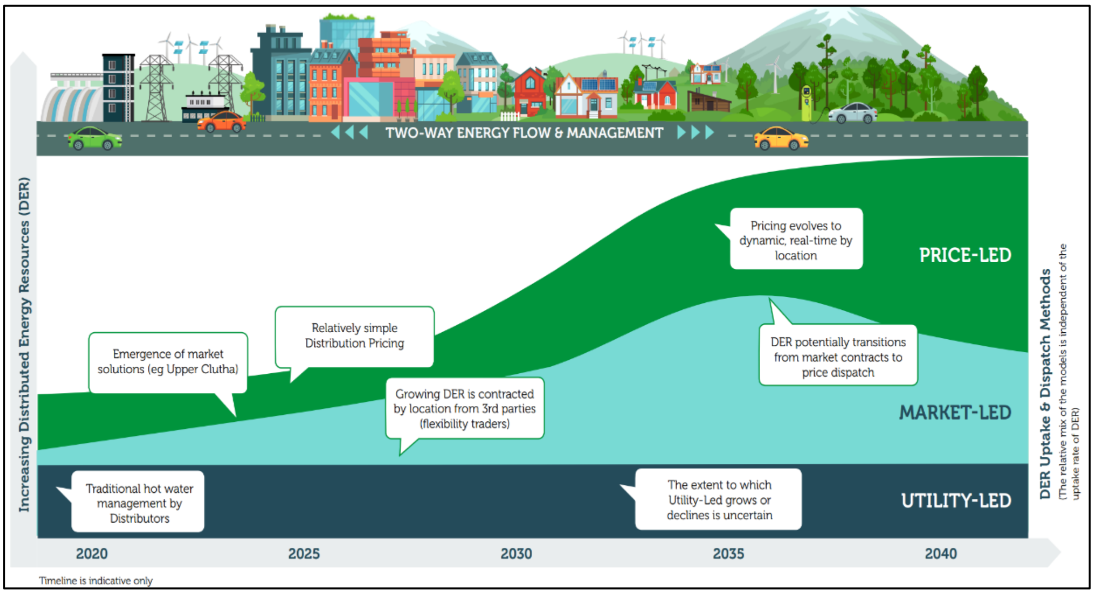
6.31. Counties Energy is conducting a trial based on following the DER aggregator model suggested in the USA by FERC Order 2222.[40] Counties has recruited aggregators of flexibility to participate in its pilot DSO that will likely follow a hybrid-style model of collaboration between the TSO (via its FlexPoint facility) and Counties (as the DSO), using a DERMS (a DER management system, using the Plexigrid product), to orchestrate aggregated DER in the trial area, including about 500 ICPs. Communication between FlexPoint, the DERMS and the DSO is to rely on IEEE2030.5.

The South Island Distribution Group (SIDG)

6.32. Starting in June 2021, the South Island Distribution Group (SIDG), which included all distributors in the South Island, funded an investigation to research new distribution operating models and their application to New Zealand. The group identified and described three models in a paper released by SIDG.[41]

6.33. As shown in Figure 2, these were an extension of the current state (the utility-led model), to the introduction of new market players and flexibility traders (the market-led model), to the future possibility of real-time prices (the price-led model).

Figure 2 – SIDG DSO models



[40] Federal Energy Regulatory Commission (FERC) https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy.

[41] See Developing our roadmap with you - SIDG

6.34. Note that the ENA tested and developed these models/enablement modes and developed them into the direct access mode (rather than utility-led), contracted mode (rather than market-led) and price mode, and added the emergency mode.

6.35. The SIDG models are different to those being explored in Great Britain or Australia, or by the ENA or the NEG, although as mentioned the ENA FNF work also emphasised and modified these modes of DER enablement.

- The utility-led model represents the uncertain extent to which distributor control of hot-water cylinders will persist and/or will be extended to other types of DER, some possibly owned by distributors
- The market-led model sees aggregators in control of DER, using DERMS, while the role of distributors is to optimise the dispatch of flexibility services from aggregators, using flexibility management systems (FMS)
- The price-led model assumes sufficient visibility of the distribution networks to implement real-time distribution price signals for DER coordination.

6.36. The SIDG view is that the three operating models will co-exist, but that over time the increasing degree of DER integration will favour a move towards market-led and price-led models, and this will correspond with the emergence of the DSO role. This corresponds to the thinking in the ENA's FNF project, around DER enablement modes.

6.37. Therefore, although the SIDG foresees the coexistence of the utility-led, market-led and price-led modes/ models for some time yet, nevertheless the SIDG models are portrayed as being successive states rather than alternative future options.

Q6. 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?

7 Alternative DSO models for New Zealand

7.1. The different models proposed by organisations in New Zealand and overseas show a range of options for how key functions for operating the distribution system might be assigned between the DSO, TSO, aggregators, and/or an independent third party or parties. As stated in the Electric Power Research Institute (EPRI) 2023 Technical Update,[42] they all describe a comprehensive set of interactions and responsibilities needed to plan systems, connect resources, operate markets, and financially settle service providers.

7.2. The aim of this paper is to provide a basis for further engagement and encourage input and views from stakeholders. We want any models to help us understand the kinds of changes that will best meet the success criteria we have outlined, whilst identifying and minimising risks.

The Authority is putting up three DSO models for consultation

7.3. The three models are:

- Total TSO model
- Total DSO model
- Hybrid model

7.4. We do not discuss in any detail the option of an independent DSO (iDSO) although we have seen that in Great Britain Ofgem has assigned an independent party (Elexon) to deliver a subset of DSO services (market facilitation), whereas distributors in Great Britain are transforming themselves into DSOs to deliver other DSO services.

Assessment criteria for the three DSO models

7.5. In the next paragraphs and in Table 1 we explain the differences between the three DSO models and we mention some pros and cons of each. Thereafter in Table we evaluate the models according to the following assessment criteria: consumer outcomes; cost; implementation feasibility; and system benefits.

What about the option of an independent DSO (iDSO model)?

7.6. Assessments in Australia and Great Britain noted the iDSO model (or 'aggregator of aggregators' model) is likely to be costly to implement, as it requires duplicating resources that the TSO and/or distributors already possess. Furthermore, an iDSO would need to engage in a three-way exchange of information between itself (the iDSO), the TSO and distributors, whereas there would be two-way exchanges between the TSO and any distributors-as-DSOs.

7.7. However, distributors that take on the role of DSO could have interests that are misaligned if they are also involved in owning and managing DER. This is

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42 EPRI 2023 Technical Update: Enabling DER Service in Distribution Operations (Page 44).

potentially an argument for appointing an independent body as an iDSO that performs a limited subset of DSO functions, such as aggregating all aggregated DER, and facilitating market development such as creating standardised products and one or more flexibility services trading platforms.

7.8. Alternatively, to avoid the costs of an iDSO and the potential for misaligned interests, there could be a rule that distributors must ring-fence their flexibility service activities if they wish to become DSOs, which is roughly the position in both Australia and Great Britain. This could be achieved in New Zealand by applying the arm's length rules in Part 6A of the Code to such distributors.

7.9. In 2024, the Authority introduced draft guidance principles for distributors involved in the market for flexibility services.[43] The draft principles would require distributors to treat other parties, such as aggregators, even-handedly.

7.10. When we tested this draft guidance with distributors, aggregators and others, feedback predominantly related to distributors' existing use of hot water cylinder management by ripple control. We are now analysing the feedback and identifying the next steps. When this guidance is finalised, it could apply to any distributors that might become DSOs.

7.11. Given the iDSO option would likely be more costly than the other options, it could instead be considered to perform a subset of DSO functions to remedy misaligned interests where distributors that opt to become DSOs are also involved in owning DER and providing flexibility services. Such an iDSO might only be required once the market for flexibility services is more developed. There could also be a need for a different allocation of the DSO function of integrated distribution system planning, between distributors, the TSO and Transpower as grid owner.

7.12. Notwithstanding, the Authority would like to hear whether stakeholders think the Authority should also consider the iDSO model as a fully-fledged DSO option.

Q7. 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 that decision wait until the market for flexibility services is more developed?

Features of the three DSO model options

7.13. Table 1 provides a summary of the three DSO models we are proposing for consideration by stakeholders.[44] To reiterate, we welcome feedback on these and any other models (eg, the iDSO model) that we do not discuss in as much detail as the three models chosen.

7.14. Note that all three options contemplate allocating the DSO functions in different proportions between the TSO and one or more distributors-as-DSOs. A full iDSO

[43] Guidance on distributor involvement in the flexibility services market.

[44] The characterisation of these models, the allocation of DSO functions, and the pros and cons of each model, draws on a review article: A Review on TSO-DSO Coordination Models and Solution Techniques.

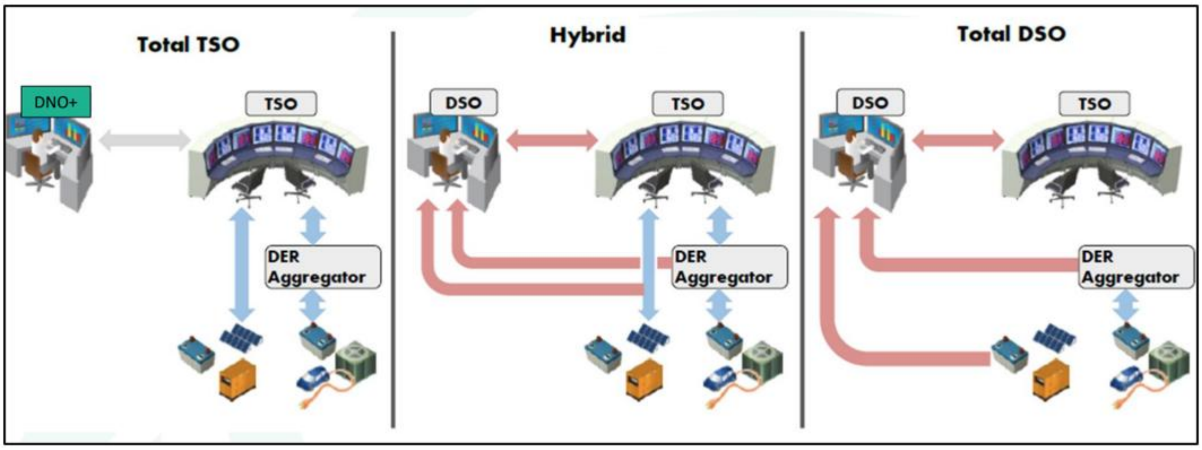
option would involve allocating the same functions between the TSO, the iDSO and the distributors.

7.15. On the other hand, an iDSO could be created or appointed to perform a limited (and more affordable) subset of market-development functions to alleviate any concerns of misaligned interests for distributors performing DSO functions as well as providing flexibility services.

Table 1 – DSO model options for consultation

	Total TSO	Hybrid	Total DSO
Market organisation	Single central market.	Central market comprised of wholesale and ancillary services. Can include local market(s) for regional system service provision from DER.	Central market comprised of wholesale and ancillary services. Can include local market(s) for regional system service provision from DER.
Allocation of DER flexibility	TSO priority.	TSO and DSO.	DSO priority.
Role of distributors in DSO	Provides real-time operational data from the distribution network to the TSO.	Responsible for validating DER bids to guarantee network integrity. Can procure DER services from the central market for distribution-related purposes.	Operates a local market for resources connected at distribution level and is responsible for local congestion management.
Role of TSO	Responsible for dispatch of transmission and distribution connected resources (accounting for both transmission and distribution network constraints).	Responsible for dispatch of transmission and distribution connected resources (only accounting for transmission network constraints).	Responsible for dispatch of transmission connected resources and the central ancillary services market.
Aggregators	Submit DER bids to TSO for validation and sale.	Submit DER bids to DSO for validation and sell DER through TSO.	Submit DER bids to DSO for validation and sale.

Figure 3 – Three primary design models for TSO-DSO coordination (source: EPRI[45])



Option 1: Total TSO model

7.16. Figure 3The total TSO model in Figure 3 centralises the coordination and dispatch of traditional generation resources and DER under the TSO. Under this approach, the TSO considers both transmission and distribution network constraints, including local needs of distributors for network support services, to ensure system reliability and operational efficiency.

7.17. The distributor/s as DSO play a supporting role, focusing on providing real-time operational data from the distribution network to the TSO. Beyond this, the DSO's responsibilities remain limited to maintaining and operating the distribution network, making necessary investments, and conducting maintenance activities. Consequently, the interaction between the TSO and DSO is primarily an exchange of real-time data about network participants and configuration, and asset status and constraints.

7.18. In this model, the dispatch process follows a structured sequence. DER submit their bids directly (or via an aggregator) to the TSO, which then validates the bids, computes dispatch schedules for generators and DER, and issues dispatch commands. This approach enables technology-agnostic DER controllability, where the TSO models power injections or absorptions without requiring detailed DER operational data.

7.19. However, this model does not support simultaneous TSO and DSO utilisation of DER services, posing integration challenges. However, a DSO can still contract directly with DER for services to resolve constraints. The model simplifies TSO-DSO coordination but introduces risks, including potential inefficiencies in service

45 EPRI 2023 Technical Update: Enabling DER Service in Distribution Operations (Page 45).

facilitation and scalability issues as DER penetration increases. And as the EPRI 2023 Technical Update notes,

> *The total TSO model introduces the exchange of dispatch or control messages that bypass the DSO domain, potentially affecting safety, reliability, security, and power quality at the distribution level. This is because the DSO remains responsible for maintaining safety and reliability on the distribution system but is not able to override the dispatch of distributed resources by the TSO. It is also unclear how distributed resources would be dispatched to resolve distribution system constraints given that the TSO is focused on the broad balance of supply and demand across transmission and distribution.*

7.20. Also, transferring significant volumes of real-time data and interpreting distribution network requirements presents challenges for the TSO, which may lack distribution-level expertise.

Summary of the key pros and cons of Option 1: Total TSO model

7.21. Pros:

- The TSO is accustomed to dispatching resources so it would have an advantage in taking on additional responsibility for dispatching DER.
- If both DER uptake and network visibility improve rapidly, the total TSO model could be an efficient solution to minimise total cost.

7.22. Cons:

- TSO would face a massive increase in data acquisition and processing to extend its system operation function into all 29 distribution networks.
- The tier bypass issue as noted above, whereby dispatch messages can bypass the DSO domain regardless of potential constraints.
- The total TSO model represents centralised, top-down control. This could be at odds with a decentralised power system (and mindset) that aims to facilitate consumer uptake, control, and value maximisation of their DER.

Option 2: Hybrid model

7.23. Figure 3The hybrid model in Figure 3 divides responsibilities for TER and DER between the TSO and DSO. While the TSO retains responsibility for centralised dispatch, it does not account for distribution network constraints. Instead, the DSO validates DER service bids to ensure network integrity before these bids are used in the dispatch process.

7.24. This validation process enhances coordination by allowing the DSO to verify bids either before or after submission to the TSO. In some configurations, DER may send validated bids directly to the TSO or simultaneously to both the TSO and DSO. Additionally, the DSO can use DER services to address distribution-specific needs, such as mitigating network issues or deferring investments.

7.25. The coordination process under this model involves the following steps:

(a) DER submit bids directly to the TSO.

(b) The DSO is informed about the bids.

(c) The DSO validates the bids, then transmits the validated bids and requests to the TSO and/or DERs.

(d) The TSO performs the dispatch and communicates dispatch commands to the DER.

7.26. The model allows both the TSO and DSO to utilise DER services, contingent on market design and established priorities. For example, the DSO may prioritise DER services for local voltage or congestion issues, while the TSO focuses on energy balancing. This could work well with New Zealand's relatively large distributed generating stations embedded in distribution networks.

Summary of the key pros and cons of Option 2: The Hybrid model

7.27. Pros:

- Computational and modelling requirements are reduced relative to the total TSO model.
- The DSO's knowledge of its own network operation arguably enables it to facilitate more DER services than the total TSO model, and the DSO does not need to share operational data with the TSO.
- The hybrid model is a compromise between the total TSO and total DSO models in that distribution-connected DER can participate in the wholesale market through DER aggregators and/or distributors-as-aggregators, while distributors have some oversight of the participation and dispatch of those DER as needed to maintain the safe and reliable operation of the distribution system.

7.28. Cons:

- The joint control by the TSO and DSO could lead to 'duelling' between them over who has priority/primacy over the use of the DER services that are dispatched. This could raise the question of whether an independent market operator or facilitator is required (as mentioned, Elexon was appointed to that role in Great Britain).

7.29. Neutral:

- The incentives on the DSO to facilitate DER services are mixed. More DER services could increase wear and tear on network assets but on the other hand, DER used to provide non-network services should relieve pressure on network assets and delay their replacement or strengthening.

Option 3: Total DSO model

7.30. Figure 3The total DSO model in Figure 3 centralises the coordination and dispatch of DER under the DSO, with the TSO maintaining responsibility for dispatchable resources generating in excess of 10MW. This model is flexible and can operate with or without a distribution-level market.

7.31. In the absence of a distribution-level market, the DSO validates DER service bids and aggregates them, effectively clearing the market behind a grid exit point (GXP), before submitting the aggregated bids to the TSO. The TSO dispatches aggregated DER volumes, and the DSO coordinates individual DER to match the TSO's requirements. The sequence is as follows:

(a) DER submit bids to the DSO.

(b) The DSO validates and aggregates bids before sending them to the TSO.

(c) The TSO dispatches aggregated DER services and sends the commands to the DSO.

(d) The DSO dispatches individual DER to fulfil the TSO requirements.

7.32. When a distribution-level market exists, the DSO can use DER services for local network needs before interfacing with the TSO. Two approaches are possible:

(a) Market clearance first: The DSO clears the distribution-level market and sends only surplus DER bids to the TSO. Dispatch commands are issued by both the TSO and DSO.

(b) Target-based coordination: The TSO sets targets at the TSO-DSO interface, and the DSO uses the distribution-level market to meet these targets while maintaining network integrity.

7.33. In either scheme, the DSO may optimise DER utilisation for local issues, such as voltage control or congestion, while addressing TSO requirements.

Summary of the key pros and cons of Option 3: The Total DSO model

7.34. Pros:

- There is no need for the DSO to exchange network operation data with the TSO. The Total DSO model is potentially most efficient at maximising the use of DER services that are not requested by the TSO, as the DSO leverages its knowledge of distribution assets to re-optimise their use.
- All constraints and network needs on the local network will be met – and there would be no duelling with, or infeasible dispatch by, the TSO.
- The total DSO model can simplify grid operation for the TSO because a single aggregated resource is presented at each transmission-distribution interface, as opposed to potentially numerous aggregations under the total TSO or hybrid DSO models.

7.35. Cons:

- Though the DSO might have the visibility and authority to optimise resources across its system, this is not a familiar task for distributors.
- As the EPRI 2023 technical Update notes, issues of transparency and priority arise when the DSO aggregates DER that are distributor-owned, consumer-owned and managed by third-party aggregators. A potential solution to any

misalignment of interests is an independent DSO, or a less costly option would be to rely on the Authority's existing guidance principles for distributors involved in the market for flexibility services. A third option would be to appoint an independent market facilitator as is done in Great Britain.

How might consumers be affected by the choice of DSO models?

7.36. From the consumer's perspective, it is unlikely they will be aware of any decision having been made about applying one DSO model rather than another. Instead, consumers might notice an impact on the price they pay for electricity, and/or ease of deriving some value from their DER.

7.37. In this regard the total TSO model could be the least-cost solution, especially if the uptake mainly involves large DER, and that might be beneficial for electricity affordability for consumers. On the other hand, the total DSO and hybrid DSO models could provide more opportunities to consumers for the use of their DER and maximise the value they derive from participating in the power system as 'prosumers' – suppliers as well as consumers.

7.38. It is also important to compare how each model is likely to promote the process of price discovery in the market for flexibility services. If one model is better at approaching the wholesale market ideal of security-constrained economic dispatch over time, that should maximise the volume of transactions on the market for flexibility services and deliver benefits to consumers. However, it is not yet clear what model will most stimulate the uptake and deployment of DER and any of the three models appear capable of promoting efficient price discovery processes.

The Authority's preliminary views on the DSO models

7.39. The Authority tentatively prefers the hybrid DSO model, though any of the three models could be fit-for-purpose and as mentioned, all have their pros and cons. Close coordination and collaboration between DER owners, aggregators, distributors, and the TSO are required regardless of the nominal roles assumed by each of these players in the distribution sector.

7.40. The Authority has observed that some distributors have already started performing DSO functions in coordination with the TSO in a way that resembles the hybrid DSO model. The preference for a hybrid-managed model among distributors and the TSO might strengthen if they decide they would like to play to their strengths, which could be portrayed as distributors knowing the most about their networks and the system operator being expert in current dispatch processes.

7.41. If there is more than one DSO, the TSO will require consistent process and interface with each, for example compliance with standards and protocols, to ensure interoperability and the communication of instructions. DSOs, distributors, aggregators and the TSO would also need to agree on how to define and value the flexibility services (eg, quantities in units of MWh) and establish which uses have priority or primacy over others. There are clearly many details to resolve and codify.

7.42. In terms of choosing the model that best suits consumers, this could depend on the scale of new DER. If it is large, there could be a case for choosing the total TSO model on efficiency grounds, even if this would require devoting substantial resources to acquire detailed distribution network information to perform the DSO role.

7.43. If the advent of large DER or large aggregations of DER is not expected to be very dramatic, then the total DSO or hybrid DSO models might be better placed to facilitate the growth of the market for flexibility services and thereby boost DER uptake by consumers.

7.44. At this stage any model or models adopted for further consideration will need to be sufficiently flexible to accommodate consumer needs in a vastly expanded electricity system.

Table 2: Comparison of options

Option	Evaluation criteria: Consumer outcomes	Cost	Implementation feasibility	System benefits
Total TSO model	Centralised TSO control may hinder consumer empowerment and decentralised DER value realisation.	Lower upfront cost if DER uptake is rapid. High ongoing complexity and TSO resourcing needs (data acquisition, distribution network expertise).	TSO experience advantage in dispatching DER; But challenging for TSO to scale operations to 29 distribution networks.	DER services must be centrally dispatched; limited local optimisation. Centralised coordination and dispatch but risks inefficient dispatch for local constraints.
Total DSO model	Best for enabling consumer participation and maximising DER value, if transparency is maintained.	Higher implementation cost. DSOs would need to develop new skills, but less burden on TSO.	Challenging. Requires major capability uplift for distributors to act as full DSOs.	Maximises DER usage locally before engaging with TSO. Enables full optimisation of DER resources. Most efficient for local constraints.
Hybrid model	Balanced. Good opportunities for DER owners to participate and be rewarded.	Moderate cost. Lower data burden compared to Total TSO model. Some complexity managing TSO-DSO interactions.	More feasible. Builds on existing distributor and TSO capabilities.	Good coordination and dispatch efficiency. DSOs validate bids; reduces dispatch risks across local networks.

Rating scale

Excellent Good Moderate Poor Very poor

The Authority would like your input on the DSO models

Q8. What do you think about the three DSO models proposed by the Authority?

Q9. Do you prefer one model over the others?

Q10. 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?

Q11. 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?

8 Next steps

8.1. The operation of the power system is based on a centralised, synchronous generation-based power system. New Zealand is moving towards a low-emissions, decentralised energy system, with an increasing role for inverter-based, variable and intermittent sources of generation, as well as significant distributed energy resources and demand-side flexibility. The Authority wants to ensure the power system can adapt to these changes and enables consumer participation and innovation.

8.2. From the February 2024 consultation, it is evident the power system faces challenges including the need for greater coordination of system operation and a need for clarity on the capabilities, roles and functions of distributors. While the need for improved coordination is being addressed by the Authority in other work, this paper provides three options for consultation on alternative DSO models.

8.3. The Authority has some preference for a hybrid model (combining the capabilities and functions of the TSO and one or more distributors as DSOs), partly as this appears to be emerging in the absence of any regulatory stipulation to the contrary.

8.4. However, we would not wish to pre-empt the feedback from stakeholders on the issues raised, or on the merits of the full range of proposed options in this second FSO consultation. Once we have received and evaluated feedback, we will be in a better position to decide what option or options are best to take forward for the future architecture of the distribution system and what form (and number) of DSOs are likely to deliver the best outcomes for consumers – as they become prosumers, in a power system that is becoming more decentralised and flexible.

8.5. Therefore, we intend to publish a decision paper in the first half of 2026, confirming the appropriate choice of DSO model after taking into account submissions on this paper and further engaging with stakeholders if required. The decision would be on what DSO model should be applied and whether this should include a role (even a limited role, eg market facilitation) for an independent DSO, whether now or once the market for flexibility services is more developed.

8.6. The Authority will support the development of the options or the choice of an option, using its regulatory levers such as issuing guidance, amending existing guidance, or by creating Code obligations.

Appendix A Format for submissions

Submitter	

Questions	Comments
Q1. Do you agree with the 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?	
Q2. Do you think we are correct that the themes we identified in submissions to the initial consultation paper mean we should focus mostly on system operation at the distribution level, and on the new functions required for effective distribution system operation?	
Q3. 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?	
Q4. Do you agree with how we have defined the problem, as the need for a more coordinated framework of integrated system operation?	
Q5. In your view, what aspects of the Australian and British deliberations around DSO models are relevant to New Zealand?	
Q6. 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?	
Q7. 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 that decision wait until the market for flexibility services is more developed?	
Q8. What do you think about the three DSO models proposed by the Authority?	
Q9. Do you prefer one model over the others?	
Q10. 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?	
Q11. 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?	

Appendix B Our response to other matters raised in submissions

B.1 Beyond the three themes in the submissions covered in the body of the paper, we identified several other matters.

Transpower potential misalignment of interest

B.2 The first of these is the future role of the transmission system operator and whether there is a misalignment of interest between Transpower's roles as grid owner and system operator. Some submitters acknowledged existing measures to mitigate these conflicts, including regulatory constraints imposed on Transpower by the Commerce Commission.

B.3 Some submissions referenced institutional changes in Great Britain, where the system operator has been separated from the grid owner through a state purchase of the power system operator from National Grid plc. Concerns in that case included the potential for National Grid to over-invest in transmission and influence the system operator's decisions. While some submissions suggested similar changes be considered for New Zealand, others pointed out that Transpower is already state-owned with a ring-fenced system operator function contracted to the Authority and a grid owner role regulated by the Commerce Commission. These submitters considered that further separation would involve incurring significant additional costs for questionable benefits.

Data for network visibility

B.4 Several submissions noted the need for better access to more data, to improve network visibility and contribute to more coordination of distribution system operation. The Authority currently has a workstream looking at ways to improve the visibility of network capacity. This involves a stocktake of the capability and use of the meter fleets connected to the low-voltage networks, as well as a review of the commercial terms and conditions that may affect the use of telemetry from the existing meter fleets. This work will unpack the ability of the current meter fleet to provide network operating data and any barriers to accessing this information by participants. It will also consider other matters relevant to this workstream. We believe better visibility of network capacity will contribute to the resilience, efficient and safe operation of networks, and support outcomes of the FSO work.

B.5 In addition, it is notable that the Commerce Commission recently approved a step-change increase in non-exempt distributors' spending on data so they can better monitor their networks.[46] These allowances could go some way to alleviating the data affordability issue, at least for distributors, noting that such costs are ultimately borne by consumers, although the rewards for these costs are the savings related to greater reliance on consumer-owned DER in the power system.

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46 Commerce Commission: 2025 reset of the electricity default price-quality path.

In June 2025, the Authority will be gathering information on barriers to, and opportunities for greater digitalisation across the electricity system. Digitalisation aims for a transparent and interoperable digital ecosystem, where data can be shared and used for improved decision making by consumers, participants and innovators. The information gathered on work underway by the industry will help us determine the work programme that will get us to our desired future state for this ecosystem.

Standards and protocols for inverters and DER

B.6 Submissions also noted the importance of implementing and promoting compliance with inverter and DER device standards and communication protocols. This should ensure interoperability and ultimately facilitate better coordination of system operation. Common standards should facilitate consumer participation in providing flexibility with their solar/battery/inverter investments and will enable service providers to engage with more consumers and aggregate appliances from many different manufacturers. The adoption of relevant communications standards and the uptake of compliant devices should facilitate interoperability and contribute to efficient system operation, rather than raise barriers to participation in relevant markets.[47]

B.7 The EEA is tackling various aspects of standards as it works to produce several guidance publications, via its Streamlining Connections project. Separately, EECA may be empowered to develop common connectivity and interoperability standards for energy-using products.[48] EECA can advise on common standards from a smart technology perspective, and this is likely to become part of their future regulatory remit in some form. From this perspective, there are three core components to be aware of, communication protocol, product response, and product information. For smart technology to work at scale across participants, it is important to standardise what protocols are used, what information can be exchanged, and how products can respond.

Peak capacity issues

B.8 The FSO consultation paper noted the increasingly variable and intermittent nature of new renewable generation sources, which means demand-side flexibility may be needed to offset renewable energy shortfalls during peak periods of demand. Submissions by the system operator and others raised concerns about the need for the Authority to support the electricity system to better coordinate resources during peak demand periods.

B.9 In a recent decision paper on developing solutions for peak capacity issues, the Authority addressed several issues relevant to system operation, including ancillary

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[47] The "Mercury" initiative in the UK is a good example of interoperability protocols. Mercury aims to: "… *connect together all types of low-carbon equipment--no matter the brand--and to utility providers, in order to provide better grid management and benefits for consumers.*

[48] In November 2024, Cabinet agreed to amend the Energy Efficiency and Conservation Act 2000 to enable the Minister for Energy to prescribe demand flexibility capability requirements for energy-using products, services and systems.

services, the market participation of BESS, and improvements in outage information coordination.[49]

B.10 The Authority will be working to promote flexibility and competition in the wholesale and ancillary service markets. This includes work to enhance market participation tools for BESS, and measures to reward industrial consumers for providing short-term DSF.

Common quality obligations

B.11 Power quality challenges are growing due to the increase in variable and intermittent (and inverter-based) generation sources like wind, solar, and DER. Submissions to the initial FSO consultation paper indicated the potential impact of aggregated DER on measures of power quality and therefore system operation.

B.12 As part of addressing these challenges, the Authority is reviewing the common quality requirements in Part 8 of the Code. We want these requirements to enable evolving technologies, particularly inverter-based resources, while also addressing common quality-related challenges posed by these technologies.[50] Issues we are addressing include more frequency variability, larger voltage deviations, reduced system strength and inertia, and changing harmonic levels. Resolving these issues will be important to support future system operation.

Innovation and regulatory sandboxes

B.13 Some submitters to the FSO consultation, including Transpower, recommended the Authority introduce regulatory sandboxes to support innovation pilots. These sandboxes could offer guidance, support, and possibly Code exemptions for defined periods, allowing trials that, if successful, could encourage broader adoption of flexibility services, which are essential for operating a renewable-based grid with intermittent resources like wind and solar.

B.14 In this regard the Authority updated the guidelines on Code exemptions in May 2024, to include a section on industry trials.[51]

B.15 The Authority recently launched the *Power Innovation Pathway (PIP)*[52] programme to provide innovators with easy access to regulatory guidance and support, promoting a more competitive, efficient, and reliable electricity market.

B.16 The Commerce Commission has announced funding for distributors for Innovation and Non-Traditional Solutions of up to 0.8% of their allowable revenue for the next (five-year) regulatory period from April 2025.[53]

49 Electricity Authority, Potential solutions for peak electricity capacity issues. Decision paper, July 2024.

50 Electricity Authority, Part 8 Common Quality Requirements Review, June, 2024.

51 Guidelines on Code exemptions.

52 Power Innovation Pathway.

53 Commerce Commission: 2025 reset of the electricity default price-quality path.

Other initiatives being addressed by Authority work

B.17 The Authority is also pursuing consumer-centred initiatives, such as the Multiple Trading Relationships (MTR) and switch process review, which will be released for consultation in 2025. Some submissions to the FSO consultation pointed out that MTR could allow consumers more choice over the way they use and benefit from their DER. MTR could facilitate more competitive flexible services offerings to consumers with DER. If MTR increases the uptake, coordination and exploitation of DER, overall system operation would be enhanced.

Appendix C Existing arrangements for system operation

C.1 The Authority's February 2024 consultation document provides a comprehensive overview of power system operation in New Zealand.[54] This section summarises the current arrangements.

The system operator coordinates the power system

C.2 Most of the country's generation capacity is dispatched through the wholesale electricity market. This is the case for grid connected generation and distributed generation (i.e. generation connected to a distribution network) above 30 MW capacity.[55]

C.3 Transpower, in its role of system operator, is responsible for the forecasting, scheduling and dispatch of electricity in real time in a manner that avoids fluctuations in the frequency and voltage of electricity supply, or the disruption of electricity supply.

C.4 The system operator has high level, output-focussed principal performance obligations (PPOs) in relation to the real-time delivery of common quality and dispatch of electricity. PPOs also include a 'plan to meet' obligation. These PPOs may be summarised as operating the power system to maintain frequency and voltage in real time, to avoid a 'cascade failure' of the power system.

C.5 The system operator forecasts demand in 30-minute intervals (trading periods) throughout the day. Generators offer electricity in price and quantity tranches. Generator offers are ranked from lowest to highest price and placed in a stack.

C.6 The system operator's market tools select the most efficient combination of offers from cheapest to most expensive to meet the forecast demand and provide reserve power. Cheaper renewable energy tends to lower spot prices, while more expensive thermal generation raises spot prices.

C.7 In summary, the dispatch schedule considers generators' competing supply offers, the level and location of electricity demand and the available capacity of the transmission network over which electricity can be conveyed. By modelling the actual transmission grid in the market tools, the final dispatch schedule takes system losses and constraints into account.

C.8 The system operator has a key coordination role in responding to grid emergencies, which can have localised, regional, island-wide or national scopes. In this role, the system operator works with the grid owner, generators, distributors and directly grid-connected consumers to assess the situation and plan actions to stabilise and ultimately respond to the circumstances. This is a critical role in events such as Cyclone Gabrielle that severely affected the Hawkes Bay and Gisborne regions for months.

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[54] See Future operation of New Zealand's power system.

[55] This minimum capacity level is currently under review. Current provisions in the Code enable the system operator to require distributed generation >10MW capacity to provide market offers.

C.9 Another key role the system operator performs is procuring ancillary services to support the delivery of electricity from sellers to buyers at an acceptable level of security and quality. The system operator procures ancillary services to support it meeting its PPOs. The ancillary services purchased are:

(a) frequency keeping

(b) instantaneous reserve

(c) over-frequency reserve

(d) voltage support

(e) black start

(f) Automatic underfrequency load shedding

C.10 **Frequency keeping** service is crucial for real-time operations. The service continuously balances electricity supply and demand in real time. Any aggregate difference between system supply and demand reflects immediately in the system frequency. If supply and demand exactly match at an instant in time, this is measured as a frequency of 50.0 Hertz.

Frequency keeping requires generating units to regulate frequency. Under normal operating circumstances, this is achieved by the system operator instructing one or more fast acting generating units to vary their output within a defined band to maintain the frequency close to 50 Hertz.

C.11 **Instantaneous reserve** is also crucial to real-time operations. While frequency keeping regulates the system frequency relatively gently within a dispatch interval around 50 Hertz, instantaneous reserve addresses a more serious problem should a large generating unit or station or HVDC pole suddenly disconnect from the system. The system response to such an event is a rapid decline in the system frequency that, left unchecked, would lead to cascade failure of generation units across the system and a system collapse.

Fortunately, New Zealand has never experienced an island-wide system collapse. Instantaneous reserve has both load and generation capabilities that automatically act to rapidly restore balance between supply and demand. These reserve services are interruptible load and generation reserve and are triggered if the frequency drops below 49.2 Hertz. Generation reserve can include

- partly loaded generation units providing spinning reserve
- hydro generation units operating in ‘tail water depressed’ mode
- energy storage systems that can rapidly decrease charging and/or commence or increase discharging.

C.12 **Over-frequency reserve** is provided by generating units that can be armed when required and automatically disconnected from the power system due to a sudden rise in system frequency. This could be due to an unplanned loss of a large industrial load or the tripping of the HVDC link.

C.13 **Voltage support** is provided by generating units or reactive power assets that can produce or absorb reactive power to maintain system voltages within Code limits.

The system operator may enter contracts with parties offering voltage support compliant with technical requirements and the Code.

C.14 **Black start** is a service provided by generating stations capable of self-starting. The system operator must have this service available in each island to re-energise the power system and allow other generation and load to sequentially connect following an island-wide collapse.

C.15 **Automatic underfrequency load shedding** (AUFLS) is the very infrequently deployed last-gasp mechanism that sheds between one and four large blocks of consumer load to rebalance and 'save the system' from a total collapse.

AUFLS is not an ancillary service, rather it is a mandatory Code obligation on distributors and directly connected consumers (large industrials) in the North Island and the grid owner (Transpower) in the South Island to:

- assess the demand downstream of relevant grid exit points; and
- install and maintain relays to automatically shed sufficient controlled load to meet their AUFLS obligations at all times.

Distribution system operation

C.16 Electricity distribution networks consist of the lines and substations that convey electricity from grid exit points and distributed generation to end consumers. There are increasing numbers and capacities of distributed generating units connecting to distribution networks, including solar PV, wind, co-generation and hydro generating units.

C.17 New Zealand's 29 electricity distribution businesses (distributors) are responsible for owning, planning, building, maintaining, and operating their respective distribution networks. Distributors in New Zealand have traditionally had natural monopoly features because it has been more efficient to have a single party provide the infrastructure associated with transporting electricity within a region. However, given New Zealand's small size it has been questioned whether there should be fewer than 29 such distribution areas.

C.18 In contrast with New Zealand's electricity transmission arrangements, where the system operator and transmission network owner functions are defined as separate roles in the Act and in the Code, a distributor's asset ownership and network operations roles are more integrated. A small number of distributors have arrangements with other distributors to provide network management services on commercial terms, but this is not a widespread practice.

Operating a distribution network in real time or near real time has some of the same functions that the transmission system operator carries out for the national grid. For example, operation of distribution system assets requires:

- coordination of local voltage at voltages below the grid exit point.
- fault response across a wide range of contingent events.
- addressing local network issues such as network damage from vehicle collision.

- widespread emergency condition response, such as severe weather events, earthquakes etc.
- planned asset outage coordination.
- peak demand management.
- switching for network reconfiguration, eg, for commissioning new assets or in response to network congestion.
- operation to respond to congestion due to increasing levels of distributed generation.

C.19 With the rising importance of DER, there are new and more complex functions required for distribution system operation. Therefore, the question arises whether one or more distributors should perform these functions on top of their network ownership role, or whether the system operator or third parties could perform one or more of the new functions involved in distribution system operation. We address that question later in this paper.

Appendix D Glossary

Architecture	The design of the system of inter-relationships between participants and other parties and their activities, and how effectively it will achieve maximum consumer benefit from DER.
Aggregators/ flexibility traders/ flexibility service providers	Businesses that aggregate DER from many households and/or businesses and create offerings for the flexibility services market.
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code 2010
CER*	Consumer-owned energy resource: A collective term for consumer-owned energy system assets. These can include demand, storage and generation assets including EV charging, heat pumps, white goods, batteries, and rooftop, solar or wind.
Decentral-isation*	Refers both to the general trend of smaller scale sources of generation and storage, but also a trend towards decisions being made at a smaller scale when it comes to the energy transition.
DER*	Distributed energy resource: Any energy asset connected to the local distribution network, as opposed to the transmission network. Includes rooftop solar panels, EVs, batteries, hot water cylinders, and combined heat and power schemes of any scale.
DERMS	Distributed energy resource management system: Refers to both the business processes and software tools for managing DER. Business processes include selling, contracting, operating, and making payments for controllable DER portfolios. The system aspect involves the software and digital information flows that enable the control of DER.
DSO*	Distribution System Operation / Operator: Operation – the set of activities that are needed to support the transition to a smarter, flexible and digitally enabled local energy system. Electricity Distribution Businesses / Distribution Network Owners (EDBs/ DNOs/ distributors) have been building capabilities in planning, operating and market facilitation of flexible resources to drive more efficient development and use of the decarbonising power system. This differs from the more traditional responsibility of an Electricity Distribution Business, which is to

	take power from the transmission network and deliver it at safe, lower voltages to homes and businesses. Operator – an entity (eg, a distributor, system operator or independent party) performing distribution system operation functions, or a subset of those functions.
DOE	Dynamic operating envelope: A principled allocation of the available hosting capacity to individual or aggregate DER or connection points within a segment of an electricity distribution network in each time interval (usually 5 or 30 minutes).
FMS	Flexibility Management System or FMS means the technology that allows the DSO to forecast and respond to the need for, procure, manage, contract for, issue instructions to check and reward DER owners or aggregators.
Orchestration	The process of aggregation and prioritisation of distribution level bids and offers; in Australia this is referred to as optimisation.
Regulations	Electricity Industry (Enforcement) Regulations 2010

*Reproduced or adapted from Ofgem definitions