TRANSPOWER

Waikoukou
22 Boulcott Street
PO Box 1021
Wellington 6140
New Zealand
P 64 4 495 7000
F 64 4 495 6968
www.transpower.co.nz

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Electricity Authority
By email: FSR@ea.govt.nz

Transpower's submission to Authority's consultation on the future operation of New Zealand's power system

Transpower welcomes the opportunity to respond to this consultation on the future operation of New Zealand's power system.

We generally agree that the Authority has described the current state of power system operations today. We also agree that the Authority has identified the key drivers for change. These changes are significant and are beginning to impact the electricity system. It is important to address potential barriers to distributed energy resources (DER) participation and enabling greater system integration of these resources ahead of material uptake. As the Authority has rightly identified, there are important lessons from overseas jurisdictions which are further along responding to some of the issues we are facing.

We note that the Authority's paper is broad in scope. Our response focuses on the areas that we, as the System Operator (SO) and national transmission Grid Owner (GO), see as critical to unlocking a much more coordinated electricity system that enables fuller participation at all levels.

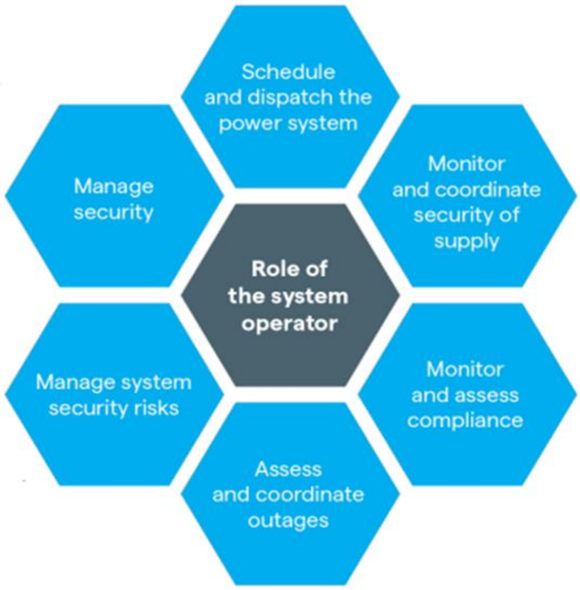
While the transition is accelerating, at this stage it is important that the industry and market can adapt to deliver benefits for consumers rather than being directed down a certain path. Our view is that incremental (low or no regret) changes should be adopted first. These include:

- establishing a common digital capability to improve access to data supporting more real time operations and system planning;
- undertaking a first principles assessment of ancillary services to ensure the system operator has access to the tools needed to provide a secure and reliable system;
- improving coordination via the use of transparent, consistent, system-wide demand and generation scenarios to deliver a more optimised (cost-effective) transition; and
- introducing a regulatory sandbox to enable innovation and help identify barriers in the current framework

The Authority should establish a digital strategy for the sector and consider a comprehensive, regularly updated DER register

Given that Aotearoa is facing important challenges in managing an equitable, optimised transition, a common digital capability is essential to support coordination between transmission and distributed system operation.

As SO, we play a crucial role in maintaining the integrity of the power system, including regulating frequency and voltage to prevent cascade failures, minimising supply costs, supporting long-term energy and capacity adequacy, and coordinating outages.



To ensure a secure, reliable, and cost-effective transition to a more distributed energy system, strong coordination between the SO and the emerging distribution system operators (DSOs) is essential.

Coordination does not mean that we, as SO, seek to 'control' the entire system. Rather, we are referring to having common digital capabilities across the SO and DSOs so that we, as SO, can support the overall operation of the power system through effective coordination and information sharing across the system.

As New Zealand moves towards a more complex system with higher DER penetration, it becomes critical to improve data exchange between the SO and DSOs. This will help manage the challenges posed by DER, such as the 'hidden load' effect[1] and potential for rapid demand changes; it's helpful too in understanding reverse flows across and within GXPs as a result of high levels of DER exports.

We need certain DER data across the full spectrum of our work as Transpower, both as SO and GO: planning, forecasting, and real-time. Shared information on DER will:

- enable transmission and distribution network planners to incorporate the effects of DER into their activities, delivering efficiencies in the process and potentially deferral of costly investments as a result;
- improve forecasting activities which will identify security risks arising from DER (e.g. cloud cover impacts on solar PV output) enabling the most efficient mitigation. Accurately forecasting net demand will be required to enable coordination of resources to serve that demand, including resources with time-bound capabilities like Battery Energy Storage Systems (BESS); and
- enable management of unexpected events and maintenance of system security if real-time visibility of controllable DER, their state, and its effects at grid connection points is provided to the DSO and SO.

<u>We recommend the Authority leads efforts to establish a Digital Strategy for the sector that would set out the roadmap for a common digital energy capability to facilitate efficient data exchange</u>, including real-time controllable DER status and dynamic distribution network constraints. This data would not only assist real time operations but would also greatly support network planning.

<u>We also recommend that the Authority consider the benefits and costs of a comprehensive and regularly updated DER register</u>. Real time controllable DER status (e.g., via inverters with communication functionality) and dynamic network constraint information is likely to be more valuable than an *ex post* information on installed controllable DER in the longer term, but a register(s) may offer additional (interim) information for planning purposes and estimation where dynamic information is not available.

[1] Hidden load is the difference between the gross demand and net demand, offset by behind-the-meter distributed generation.

At a minimum, the Authority should consider mandating certain fundamental capabilities of smart meters and data exchange.

The Authority should lead a first principles review of ancillary services to ensure that they are fit for purpose in a changing power system

Moving to a more complex power system with a greater range of generation technologies necessitates a re-evaluation of ancillary services we use as the SO to ensure grid stability and efficiency. The traditional model, heavily reliant on synchronous generation, is increasingly unsuitable due to the proliferation of asynchronous, inverter-based resources such as wind turbines, solar panels, and electric vehicle (EV) chargers. This shift calls for a "back to basics" approach, starting from first principles to identify the ancillary services essential for this new environment.

Key considerations include the need for maintaining inertia and system strength amidst growing asynchronous generation. Questions arise about the adequacy of current reserve products, like the 6 second and 60 second reserves, and whether there is room for new, faster responding reserves, potentially benefiting technologies like battery storage. Under scrutiny also is the relevance of traditional reserves classes and the potential for an inertia market to reward resources contributing to system frequency.

Additionally, the changing landscape might require adjustments in frequency keeping services to address the increasing uncertainty in supply-demand balance due to intermittent generation and demand flexibility. <u>The Authority should examine the suitability of the current frequency keeping market structure, the effectiveness of existing tools and processes, and the integration of frequency keeping procurement with the energy market.</u> This could lead to new paid ancillary services, offering revenue streams for providers and supporting investment in emerging technologies. By reassessing ancillary services from the ground up, the Authority can facilitate a transition to a power system that is resilient, efficient, and capable of integrating new technologies while maintaining grid stability.

We agree with the Authority that coordinated planning is critical to support the transition

In our role as GO, we spend a significant amount of effort each year working with EDBs to understand their planning and forecasting to incorporate it into our system planning. Our annual engagement process focuses on gathering and sharing critical data for long-term GXP demand forecasting, with an outlook of up to 15 years. This collaboration encompasses detailed analyses of demand growth, step load increases, and the integration of DER like solar, battery storage, electric vehicles, and electrified heating. We also work with our industrial customers to understand their long-term demand forecasts.

In the current financial year, we identified around 800 step load increases expected to add approximately 1,400MW by 2038, alongside 54 DER and distributed generation projects contributing an additional 830MW of generation. The high response rate from EDBs and direct industrial customers underscores the effectiveness of our engagement strategy.

Beyond annual forecasting, our increased interactions with EDBs strengthen our understanding and preparation for the impact of electrification. But there is a need for even greater alignment as we move into a rapidly changing and complex future. A clear and coordinated set of electricity growth scenarios and their underlying assumptions would greatly assist joined up efforts across industry, especially if these were the product of broad engagement across the system.

For NZGP Phase 1 we developed and consulted on our own generation scenarios, which we developed through engagement with the industry as variations to EDGS. This process worked well and set a precedent for an open, transparent process by which Transpower was able to move forward with scenarios that meet our requirements. We are extending this with our NZGP Phase 2 work, and as part of this will further develop generation and demand scenarios (discussed below).

We are working to improve coordinated network planning through Net Zero Grid Pathways

Transpower, as the GO, is taking a leadership role through our NZGP programme, aiming to provide clear, cost-effective pathways towards the electrification of New Zealand's economy by 2050. NZGP is our strategic investment work programme, and it's complementary to our annual maintenance, refurbishment, enhancement, and development work that extends the life of our existing grid assets. All the investments identified in this program of work will be assessed against the Commerce Commission's Investment Test and funded through benefit-based charges.

NZGP's objective is to ensure New Zealand's high voltage electricity infrastructure can meet consumer expectation of a highly electrified economy. It does this by looking at the demand and generation scenarios, assessing system-wide requirements and dependencies, then determining what investment options are the most net beneficial to consumers to:

- enable new generation to connect to the grid;
- accommodate both new and growing customer load bases;
- move power to where it's needed; and
- continue to provide a secure and reliable power system.

Much more work and more detailed scenario development will also be carried out over the course of this programme. We anticipate working closely with EDBs throughout this process to understand the drivers of growth at a regional level. While we have found – as noted above – that EDBs are generally very open to collaboration and data sharing, we welcome the Authority's recognition and support of the importance of working together to develop robust and detailed whole-of-system views for network planning.

Transpower has strong safeguards and regulatory oversight in place to ensure any conflicts of interest are well managed

The primary challenge facing the electricity sector in New Zealand is how to scale up our collective ability to deliver electrification at pace to support the energy transition. Separation of the system operator function into a new entity would result in additional complexity, cost, and duplication of effort at a time when we can least afford it. There are significant benefits from Transpower fulfilling both the SO and GO roles. While these roles have been split in some overseas jurisdictions, the size of New Zealand's power system and the economies of scope and scale derived from having the roles under one organisation significantly outweigh any disbenefits.

We acknowledge that there is potential for a perceived or actual conflict of interest between our dual roles. However, as the Authority notes in its paper, "Transpower has measures in place to ensure independence between its role as system operator and any other roles that Transpower has under the Code, in particular as a transmission network owner." In the appendix to this submission, we detail the ways in which we manage real and perceived conflicts of interest.

The highly regulated environment we operate in creates strong safeguards against conflicts of interest. For example, our price-quality path regulatory regime ensures our expenditure is assessed against what a prudent and efficient electricity transmission operator would spend. As part of this regime, all major capex proposals greater than $30 million[2] must also meet a rigorous investment test that ensures that they deliver a net positive benefit to electricity market participants. As the Authority also notes, we are required under Part 4 of the Commerce Act to consider whether non-network solutions are a viable alternative to network solutions and there is no preferential regulatory treatment of capital expenditure

[2] From 1 April 2025, a threshold of $20M applies until then.

versus operating expenditure. Consistent with that obligation, we regularly seek to find non-transmission solutions that are economical; we are currently seeking proposals from potential providers of non-transmission solutions in the upper South Island to help manage growing electricity use at peak times.

The Authority has recognised "the potential for conflict of interest to apply is greater where the business in question is privately owned, as is the case in the UK with National Grid plc." A key difference between the New Zealand context and that of the UK example outlined in the Authority's paper is the fact that Transpower is a fully state-owned enterprise. In particular, the State-Owned Enterprises Act requires us to act as "an organisation that exhibits a sense of social responsibility by having regard to the interests of the community in which it operates and by endeavouring to accommodate or encourage these when able to do so".[3]

The Authority should introduce regulatory "sandboxes"

While Code changes are the Authority's main lever and remit for change, in both our SO and GO roles we would like to see some additional less formal measures that support innovation and safe experimentation.

There are excellent examples internationally of regulatory "sandboxes" offering temporary waivers from existing regulations to lower barriers to innovation and distribution-connected participation. These exist in several jurisdictions (e.g., Australia, UK and Singapore) to support readily executable innovation projects with good risk management, consumer protections, and prospects for industry net benefits. Sandboxes go together with participant education and dialogue to offer fast, frank feedback and advice to innovators, including ideas on how to make a project work under existing processes before resorting to "sandbox waivers."

A key challenge facing the industry right now is demonstrating that the electricity services we deliver are, and will be, affordable for consumers. This means supporting electrification at an accelerated pace to deliver net benefits for consumers sooner. While efforts to modify rules to facilitate this transition are valuable, it's essential that these changes enable the industry's response to the transition to assist with affordability and protect consumers against unintended costs.

We respond to the Authority's questions in the appendix to this letter.

Yours sincerely,

David Knight
Executive General Manager Strategy, Regulation and Governance

[3] State Owned Enterprises Act 1986, Section 4(1)(c)

Appendix: Responses to consultation questions

Section 3: Current arrangements of the power system	
1.	**Do you consider section 3 to be an accurate summary of the existing arrangements for power system operation in New Zealand? Please give reasons if you do not agree.**
	We generally agree with the summary, but a few points could be improved and omissions noted. We consider that Table 1, provided in section 3.47, is relatively simplistic. This could be greatly improved with a more sophisticated analysis of the distinction. An example of such an analysis is given by the EPRI model of T&D functions. More importantly, we consider that this overview has omitted the role of our GO regulatory investment test for Major Capex Proposals – these being proposals for grid investments that are above $30 million in value from 1 April 2025 (currently $20 million). This test ensures that any large grid investments we make deliver net electricity market benefit to consumers; and this, in turn, assures participants that appropriate oversight is in place over our expenditure to enhance the grid. The process also requires that we seek non-transmission solutions

Section 4: Drivers of change to power system operation	
2.	**Do you agree that we have captured the key drivers of change in New Zealand's power system operation in section 4? Please give reasons if you do not agree.**
	We agree that this section provides a generally good overview of the drivers for change. There is one addition that we consider important to add: A key change in the power system of the future is the increasing use of the internet as a communication layer to DER. This adds a new point of vulnerability to system operations. In the case of a widespread network outage, this could become a point of failure in the system. As such, it may become increasingly important for system operations to account for this risk in the provision of reserves. There is a balance between resiliency and the cost to connect, but resiliency risk can be offset centrally at a lower cost through reserves. We note that cyber security is a longstanding theme in the FSR programme roadmap; we note, furthermore, that cyber security only covers part of the risk we are highlighting here. Network connectivity can also be interrupted by natural disasters, for example, so it is not necessarily the result of intentional and nefarious actions. Equally, the mitigations required are more than better cyber security.
3.	**Do you have any feedback on our description of each key driver in section 4?**
	Other than the points highlighted above, we agree that this section captures the key drivers of change well.

Section 5: Possible challenges and opportunities in power system operation	
4.	**What do you consider will be most helpful to increase coordination in system operation? Please provide reasons for your answer.**

Section 5: Possible challenges and opportunities in power system operation

We need a common digital capability to better support coordination between transmission and distributed system operation.

To ensure secure and reliable power system operation and an affordable energy transition, strong coordination between the System Operator and future Distribution System Operators will be essential.

We note that the Authority states in its paper "Consumers … will likely decide how best to use their resources by relying on information available to them, rather than responding to instructions from a system operator."[4] We note that consumers are already participants in the electricity market – they already use information that is available to them to make decisions that impact the market. Additionally, this statement paints system operation and coordination pejoratively – the SO (and/or future DSOs will) exist(s) to ensure that resources are securely and efficiently dispatched (at least cost overall to consumers) and common quality is preserved. In particular, one of the key roles of both a SO and DSO is the management of constraints. While consumers will act to control their DER themselves (or elect aggregators to do this), there needs to be some management of the constraints of this to ensure the security and reliability of the power system at a transmission and distribution level. Hence, decisions consumers make regarding their DER must be within the parameters set by SO/DSO to maintain common quality and operate networks within their limits.

While numerous actors at different scales will be involved, there will be strong enduring value in the SO coordinating the power system and associated markets to:

- **safeguard the integrity of the power system** by maintaining frequency and voltage to avoid cascade failure of assets resulting in a loss of supply – as per the SO's principal performance obligations (PPOs);
- **maximise the benefits to purchasers of electricity** by striving to minimise the costs of supplying power, including the costs of ancillary services required to support the operation of the power system;[5]
- **monitor and co-ordinate security of supply** to ensure long term energy and capacity adequacy;
- **coordinate outages** of key power system assets, some of which will be decentralised and/or distribution-connected;[6]
- **coordinate the transmission of large generation**, which despite increases in DER is likely to continue to be a feature of the power system for the foreseeable future – there is a large amount of grid connected generation in the grid and more than 30 GW in the connection queue across various stages. DER will be a welcome complement to this, but there will also be an enduring role for transmission and the SO to coordinate the efficiency deliver of grid scale generation long into the future.

Transmission system operation today works in the context of a wholesale market run by the SO to achieve the above. Participants respond to market signals to maximise value for themselves and the broader power system. We send instructions to participants in accordance with their market bids and offers that reflect their private intention, not central "command and control."

Given the deep complexity involved in optimising the entire system in real time, it is unlikely in the foreseeable future that there will be a single whole-of-system operator. Rather, the most important problem right now is establishing systems and processes that enable the clear and efficient exchange of data and operability between the SO and future DSO layers.

[4] Section 5.5

[5] As per the SO's dispatch objective.

[6] Virtual power plants, for instance.

Section 5: Possible challenges and opportunities in power system operation

It is critical that the Authority consider the framework required for better data exchange between SO and DSO system layers. At present, the penetration of DER remains low and its integration primarily presents problems at the distribution level; but international experience has demonstrated that DER can rapidly increase to levels that begin to cause issues that threaten overall system security and reliability.

For example, as the level of distributed generation (e.g. solar PV) increases, so too does the level of 'hidden load'. Hidden load is the difference between the gross demand and net demand, offset by behind-the-meter distributed generation. This is a concern for system security because this distributed generation can suddenly cease offsetting demand (such as when a sudden storm increases cloud cover) and lead to large, rapid increases in demand.

Additionally, in the future, DSOs or other flexibility providers may control large amounts of DER and have the potential to induce large sudden demand increases (e.g. by instructing batteries/EVs to charge) or sudden demand reductions (by both reducing demand and/or injecting back into the grid across their aggregated portfolios).

In these cases, if we are not aware of or able to predict these rapid changes in system state, we may be faced with the need to urgently adjust generation in order to maintain frequency. In the case of sudden demand increases, we will need to urgently find additional generation that can quickly ramp up in time to meet this unexpected demand.

Note that this situation is exacerbated by the increase in variable renewable generation generally. We have already been working to improve its forecasting ability in the case of wind; similarly, it will be important that we have accurate forecasting capability to manage the risks associated with increasing DER penetration.

However, since DER is, by definition, connected at the distribution level, the key issue we have is a lack of visibility. We must have visibility of the aggregate effect of DER, IBR, and DSF activity at each grid connection point in order to plan – ahead of real time – for unexpected events such as plant failures or unexpected reductions in wind. Our ability to keep the system secure and stable in real time will be increasingly comprised by growing uncertainty as the uptake of these resources grows. Visibility now and into the future is critical to our ability to mitigate that risk, including through investments in the market system that utilise data.

For this reason, we regard it as critical that the Authority establish a roadmap for achieving a common digital energy capability to support the interface and operability between the SO, DSO and flexibility providers. This could be established through the development of a Digital Strategy for the sector and would ideally, the outline the needs of this common digital energy capability including:

Real-time data requirements include:

1. **Real-Time Status of DER:** Includes solar PV, Battery Energy Storage Systems (BESS), Electric Vehicle V2G capabilities and aggregated Demand Response (DR), and other aggregated DER. This should cover operational status, current output/input, and availability for demand response. *Note that Transpower does not need this at ICP level.* However, as EDBs are building their capabilities as DSOs, there could be value in understanding the operation of DER at a sub-GXP level, for example aggregated at zone sub level. We are open to understanding what data might be useful, especially for the purposes of training our load forecasting tools (discussed further below). We also note that 100% real-time coverage may not be feasible or necessary, provided that there is also an accurate and up-to-date DER register (discussed below) to allow for estimation.
2. **Real-time distributed network constraints reflected in DER bids:** We need to ensure that bids, offers for ancillary services, and potentially aggregated energy from flexible resources are deliverable and reflect actual network capacity, including at the distribution level. Real-time data on distribution network constraints could be provided, but this would require us to actively monitor all distribution networks and update bids ourselves. Another mechanism could include

DSO-level moderation of aggregated bids (assuming that flexibility traders outside DSOs also make offers to ancillary services). We are open to ideas on the mechanism, but need to be sure that DER offers can genuinely be utilised without constraints and that these are not being double counted.

We expect that ultimately, the DSO will play the key role in monitoring and moderating DER. Therefore the key problem to solve in this regard is to ensure (a) the standards, minimum functionality, and access to data to enable this; and (b) that there are systems and requirements in place to share this data with the SO. The Authority can do much to lead the change required. Chiefly we propose this includes: setting minimum standards for smart invertors and smart meter functionality to provide real-time data on Distributed Generation, DER, and power quality; and mandating open access to EDBs, perhaps with a set regulated rate of return on asset owners to enable EDBs consistent and predictable costs in accessing this data.

In addition to real-time, regularly updated (but not necessarily real-time) requirements include:

1. **DER Register:** A comprehensive and regularly updated register of DERs, categorised by type (e.g., solar PV, with/without BESS, EVs with V2G capabilities, smart hot water controls, smart controllable heat pumps). This register should detail type/technology, capacity, location, and ownership/control (direct or contracted by DSOs). *Note that Transpower does not need this at ICP level. Aggregated to GXP is sufficient.*
2. **Aggregated Flexibility Capabilities:** Information on the aggregated capability for flexibility services held by DSOs, including both directly owned and contracted resources.

We do not want to control DER – even in such cases where DER aggregators have chosen to participate in SO-notified products such as DNL[7]– in such cases the SO only send instructions to the participant, and therefore control of the DER remains with the participant. Again, in such instances, DER would be aggregated to GXP level.

However, without the data capability outlined above, it will be difficult for us to train models to forecast demand in a high DER penetration environment. This, in turn, will lead to much lower efficiency and accuracy in dispatch and reduced ability to operate the system effectively. Ultimately, end consumers will also suffer higher costs: The increased risk to the power system resulting from this lack of visibility would require much higher frequency keeping bands, increased instantaneous reserves to be carried, or prohibitive common quality asset owner performance obligations (or a combination of all three). These outcomes unnecessarily increase the costs of running the system simply because – without sufficient data capability – a large factor of power system variability and risk will remain invisible to systems that materially impact overall cost.

While it may be possible to account for some of the impacts of DER through load forecasting, without access to the underlying data a load forecast model will simply be learning correlation (what happened at the same time in known vectors such as time-of-day or weather observations) and not causation (an aggregator responding to a network limit). For example, demand response to high prices occurring at peak could be incorrectly attributed to Time of Use (TOU) pricing and be forecast to occur at the same time tomorrow. Further, to truly train and improve load forecasts, our models need to identify the difference between variance responding to ‘static signals’ (e.g. TOU pricing) vs variance responding to dynamic signals (e.g. wholesale price). These differences are essential to get right so that our load forecasts differentiate and exclude (potential) dynamic responses. Load forecasts are themselves signals for demand response so they cannot assume dynamic response as ‘baked in’ – to do so would be to mute the signals in the first place. This explains why we need a much greater understanding of DER responses. Ultimately, to achieve this level of forecasting accuracy will require data from dynamic responses to be fed back in to the models and, in so doing, we can disentangle them from future load forecasts.

[7] Dispatch Notification Load (DNL) is a low-cost path to allow smaller scale aggregated resources to directly participate in the spot market.

Section 5: Possible challenges and opportunities in power system operation

While limited improvements in forecasting may achieve some benefits for market efficiency, they will not address the potential security issues arising from a visibility of DER resources. To manage this in the absence of data may require us to use probabilistic forecasting of DER penetration and expected performance to quantify and manage these risks; for example, we might need to probabilistically model sympathy tripping of DER during a power system event. Ideally, any such activities would start with actual installed capacity of DER. As more data related to DER becomes available, these models can be further refined or retired. But ultimately, probabilistic forecasting is an inexact science and its outputs are only as good as its inputs. In order to lower end consumer costs and increase our system security, we need much greater data exchange and real-time visibility across the system.

The Authority needs to lead the development of this capability to overcome the issue of broad social benefits vs the localised cost of its development

The Authority needs to consider how this common digital capability should operate, particularly the key question of who should own the data and how this will be funded. Data is not free. The value of the right parties having access to the data they need for the secure and efficient operation of the power system would provide a net benefit to New Zealand. However, the benefit would be distributed across many electricity participants and may not naturally align with the costs of owning and operating the infrastructure.

If data has value to more than a single participant (as we expect) then one solution to this problem could be a centralised data repository managed centrally, possibly by the Authority itself with the costs appropriately socialised across those who benefit. We could also be tasked with managing this, but at present we lack the funding to do so.

Certainly a party-to-party exchange model is easier, and so, if it is possible that a common mandated data model could solve this issue, then we would support this. However, there have been recent examples where innovative pilots have not been able to involve a wide number of participants due to the prohibitive costs of accessing fundamental data. To fix this, the Authority needs to step in and address the trade-off between value-capture and wider system benefits.

Better data coordination has much wider benefits than 'merely' system operation, with the majority of value associated with resource adequacy through network deferral.

Although this question has been framed around coordination in system operation, it should be noted that improving the quality of data regarding DER would also provide benefits to network planning. As the Authority notes, the vast majority of benefit associated with DER comes from resource adequacy, so this benefit should not be overlooked. Having clear and accurate understanding of the capacity of DER and better control of it operationally would enable us as GO (as well as EDBs) to take full advantage of the ability of DER to defer (or potentially avoid altogether) the need for costly network upgrades to service peak demand.

WITS is the most efficient system for aggregated DER to engage with the SO for ancillary services.

Finally, this question has focused on the issue of better coordination between SO and DSO level for overall system operation. It should be noted that we anticipate one important avenue for DER aggregation revenue is in the provision of ancillary services at SO level itself. In 2022, we published a report indicating that we think the most efficient way for this to operate is through WITS, which is the system we already use for the provision of ancillary services. We think that there is not sufficient need to create a new system for this and it would be much more efficient for DER aggregators (including potentially DSOs) to engage in the existing way.

5.	**Looking at overseas jurisdictions, what developments in future system operation are relevant and useful for New Zealand? Please provide reasons for your answer.**

Section 5: Possible challenges and opportunities in power system operation

We regularly look to overseas jurisdictions for developments that might be applied here. However, it is important to ensure that such comparisons are done with care. This is due to many important differences in power system characteristics, technical standards, policy, regulation and industry structure. Any ideas put forward need to have been filtered through this lens. It is also important to understand the scale and stage of maturity any given development is at – activities that are in trial stages or still in the process of being finalised need to be scrutinised closely as any early learnings may be difficult to extrapolate for the whole of that jurisdiction, let alone New Zealand. We note that the EY report included in the appendix of this paper makes this hard to do because it does not help the reader contextualise the scale or stage of various developments easily. Regulatory proposals and small-scale trials are often intermingled with final policy decisions and more established initiatives.

Regulatory "sandboxes" are key development applied overseas that could work well here.

Notwithstanding the cautionary note above, we consider that the Authority could do much more to facilitate and support the transition towards a more distributed power system. In particular, while Code changes are the Authority's main lever and remit for change, we would like to see some additional less formal measures that support innovation and safe experimentation. There are excellent examples internationally of regulatory "sandboxes" offering temporary waivers from existing regulations to lower barriers to innovation and distribution-connected participation. These exist in several jurisdictions (e.g., Australia, UK and Singapore) to support readily executable innovation projects with good risk management, consumer protections and prospects for industry net benefits. Sandboxes go together with participant education and dialogue to offer fast, frank feedback and advice to innovators, including ideas on how to make a project work under existing processes before resorting to "sandbox waivers."

The system operator's primary opportunity to leverage a sandbox model would be Part 8 of the Code governing common quality. Part 8 is prescriptive as to how ancillary services are defined and procured. Innovators and the industry may benefit from us as System Operator having limited discretion as to what services we procure, how we procure these, and from whom. This would also enable us to evolve our procedures and systems to be more flexible.

In other jurisdictions, the equivalent to the Authority has taken a key role in facilitating agreement on the definition of the DSO role.

Another example internationally that the Authority might want to consider is to draw from those jurisdictions that are further along the journey of understanding and defining what DSO models may be viable; the same is true for data exchange requirements and digital architectures to facilitate flexibility management across the power system – this, we note, could have been covered in more depth in the EY review.

We encourage early work in this area, particularly on following international examples and delineating the crucial interface between the SO and DSO(s). E.g.,

- Ofgem beginning a discussion on "common digital energy infrastructure archetypes" (discussed in Question 4).
- Ireland developing a future DSO-SO operating model covering data exchange, operational interfaces and network planning.
- The state of California assessing options for DSO models, roles and responsibilities.

We recognise that EDBs are themselves also engaged in the process of coming to define what a DSO role will entail; clearly EDBs are the most impacted by this and so this is natural and appropriate. We simply encourage the Authority to take an active role in facilitating these conversations to help guide convergence on the discussions and enable a clearly defined framework which can subsequently be utilised by EDBs to support funding applications to the Commerce Commission. The flexibility that can be

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	gained by leveraging distributed resources will not materialise if distribution businesses are not funded to support required investment. We view the emerging role of DSO(s) as key participant(s) in the future electricity system and would welcome the emergence – guided by the Authority – of a clear view of how this role will function and integrate with the rest of the power system, especially us in our role as SO. Developing a shared common agreement of this early and the interoperability required will aid in developing system integration.
6.	**Do you consider existing power system operation obligations are compatible with the uptake of DER and IBR generation? Please provide reasons for your answer.**

We recommend that the Authority takes a "back to basics" approach for ancillary services – by this we mean that we should start from first principles and reassess what ancillary services will be needed for this new, more complex and distributed power system. Obligations designed for a synchronous generation-dominant grid may no longer be suitable (as they will likely fall on a smaller and smaller number of synchronous generators), which may therefore require incentivisation through paid new ancillary services that could provide revenue streams above and beyond the spot energy price. New paid ancillary services may also support investment in and participation by new and/or distributed technologies like BESS. We consider then that the FSR programme should "unbundle" and describe what services are required, then consider how to procure them on a continuum from "obligation" to increasingly complex market incentives. An obligation can, over time, evolve into more a formalised market but, to begin with, obligations are a useful place to start.

Some pertinent questions relating to ancillary services and/or obligations to support common quality include:

- Maintaining inertia and system strength as asynchronous, inverter-based resources like wind turbines, solar panels and EV chargers proliferate:
  - Are the current instantaneous reserves products (6 second and 60 second reserves) designed to arrest and reverse a sudden drop in frequency fit for purpose? Is there an opportunity to reward faster responding reserves providers such as BESS through "area under the curve" measurements and/or faster reserves products (e.g., 2 second reserves)?
  - Are reserves classes in the Code predicated on past assumptions about types of generation and load such as partly loading spinning reserve, tail water depressed reserve and interruptible load still relevant with the advent of new bidirectional technologies like batteries?[8]
  - Is there a place for an inertia market to reward synchronous resources (or simulated synchronous resources) that support system frequency when connected?
  - Given potential future system strength challenges, should the system operator consider procuring voltage support services?
- There may be an increased and/or changing need for frequency keeping services to balance temporary mismatches between supply and demand. This is due to the increasing prospect of supply-demand uncertainty through intermittent generation growth and increased demand flexibility:
  - Is the current national frequency keeping market comprised of 15 MW bands in each island likely to be suitable for the long term? These bands may have to change depending on load and (particularly asynchronous intermittent) generation growth in each island.
  - Are our current frequency keeping tools and processes fit for purpose to encourage greater participation and competition in this service? For example, there is a 4 MW

[8] Note that the Code has been recently amended to contemplate a broad definition of "generation" reserves that includes partly loading spinning reserve and tail water depressed reserve but is not limited to just those technologies.

minimum frequency keeping offer requirement due to tool constraints – this could be a barrier for smaller scale battery storage. Current frequency keeping tools also require a simultaneous energy offer from a participant – this could also be a barrier to participation by battery storage.

- Frequency keeping procurement is not co-optimised with the energy market like instantaneous reserves, which may compromise efficient, least-cost dispatch for the overall market in some situations.

Obligations placed on generation governor response could be another means of managing the increased frequency keeping needs. However, this would not offer the providers any compensation other than that already available through the spot energy price.

7. **Do you consider we need an increased level of coordination of network planning, investment and operations across the New Zealand power system? Please provide reasons for your answer.**

We commend the Authority's emphasis on the importance of coordination in network planning, investment, and operations across the New Zealand power system. Our view is that coordinated planning is integral to enabling an effective and efficient transition to a net zero economy through electrification. Efforts to increase this, therefore, are timely, relevant, and welcome.

Transpower recognises the importance of coordinated planning and regularly collaborates with EDBs on projections of growth, step loads, embedded generation, and DER.

In our role as grid owner, we understand the importance of deep coordination between the transmission and distribution networks. This is why we put a significant amount of effort into engaging with EDBs to understand their needs and projections – and this work has also been increasing in recent years.

As an example of this, we engage with all EDBs annually (typically between November and February) each year to share information and work together on accurate GXP peak demand forecasts. These forecasts run out to 15 years where possible, though many EDBs only forecast 10 years out. The information feeds into our Transmission Planning Report.

In this process, we email all EDBs with detailed spreadsheets that breakdown their projections for **base demand** growth, **new step loads** and **embedded generation projects** as well as **distributed battery, distributed solar, electrified heat,** and **electric vehicles.** We are particularly interested in step load increases. We ask EDBs to name, where possible, the third party associated with the step load also, which we use to match against other sources e.g., from EECA's RETA studies; we also seek estimates of the probability associated with each of these step loads. An example of the outcomes of this process: This year we discovered about 800 individual step increases adding ~1400MW by 2038.

We are also interested EDBs' knowledge and projections of the uptake of DER: we ask them specifically how they have accounted for the uptake of distributed energy resources (e.g. batteries, solar photovoltaics, and electric vehicles) and the electrification of heat processes in their forecasts. If they have, we seek to understand their approach and the assumptions they make about their contribution at peak times. Relatedly, we also ask if EDBs have modelled and/or see any impact from other influences such as energy efficiency, demand response or customer actions (e.g., in response to tariff changes/evolving retail offerings). This year we uncovered 54 projects and some 830 MW of generation through this process.

We find that our collaboration with EDBs in this manner is very productive and well received. This year we received responses from all but one EDB; last year we received a 100% response. We also engage with and receive responses from our directly connected industrial customers. For example, this year we received forecast updates from NZ Aluminium Smelter, NZ Steel, Methanex, Kiwirail, and Daiken Southland.

In addition to this annual process, we also have increased our regular and additional interactions with EDBs, often including staff who are working in strategic future thinking roles and more often have worked on modelled demand of future DER. For example, we have met with Powerco, Unison, Electra, Orion, Aurora, Power Net and have quarterly collaborative sessions with Vector.

Transpower is working to improve coordinated network planning through Net Zero Grid Pathways.

We have a specific program of work – our Net Zero Grid Pathways (NZGP) project[9] – which aims to ensure New Zealand's high voltage electricity infrastructure remains fit for purpose in line with the expectation of a highly electrified economy. It does this by looking at system-wide requirements and dependencies that will enable new generation to connect to the grid, accommodate both new and growing customer load bases, move power to where it's needed, and continue to provide a secure and reliable power system. NZGP is our strategic investment work programme, and is complementary to our annual maintenance, refurbishment, enhancement and development work that extends the life of our existing grid assets. All the investments identified in this program of work will be funded through Major Capex projects (MCPs).

To date, NZGP has focused on investments related to the grid backbone – we termed this stage NZGP1. This has resulted in a series of connected MCPs focused on identifying and reducing potential constraints on the grid backbone to enable the efficient dispatch of forecast new generation and reliable supply of future demand growth over the interconnected grid, for the period out to 2035. This involved projects strengthening the grid in the central North Island and Wairakei as well as upgrades to the HVDC link.

The next stage of NZGP – NZGP2 – will focus on the capacity required to support regional growth as well as taking a whole-of-system view towards an optimised transition pathway out to 2050. As part of this work, we currently have six regional engagements in different stages of development. Each works closely with the relevant EDBs to develop optimised regional plans. These include:

- Vector, with the Auckland Strategy
- Powerco, with Western BOP Development
- Venture Taranaki, with the Taranaki Energy Strategy
- Unison, with the Hawkes Bay Development Plan
- QLDC, Aurora, and Power Net with the Queenstown Long Term Supply plan
- Power Net, with Murihuku Regional Electrification Plan

These plans examine and model the best mix of transmission and distribution investment to cater to varying future scenarios.

Much more work and more detailed scenarios will also be developed over the course of this programme. We anticipate working closely with EDBs throughout this process to understand the drivers of growth at a regional level. While we have found – as noted above – that EDBs are generally very open to collaboration and data sharing, we welcome the Authority's recognition and support of the importance of working together to develop robust and detailed whole-of-system views for network planning. We also note the links between this section and our response on the need for better integration of data (see Question 5 above).

8. **Do you think there are significant conflicts of interest for industry participants with concurrent roles in network ownership, network operation and network planning? Please provide reasons for your answer.**

The bulk of our response below pertains to the transmission level, since this is the level at which we are most familiar. However, regarding the distribution level we consider that the arm's length rules have an important role to play in ensuring the avoidance of conflicts of interest. These will grow in importance as

[9] The Net Zero Grid Pathways (NZGP) first stage of proposals have been through stakeholder consultation and were submitted to the Commerce Commission (Commission) in December 2023.

Section 5: Possible challenges and opportunities in power system operation

EDBs become increasingly involved in the emergence of DSO roles and should continue to be an area of active focus for the Authority and the Commerce Commission.

Transpower has strong safeguards and regulatory oversight in place to ensure any conflicts of interest are well managed.

We acknowledge that there is some potential for a perceived or real conflict of interest between our dual roles as both grid owner (GO) and system operator (SO). As the Authority notes in its paper, "Transpower has measures in place to ensure independence between its role as system operator and any other roles that Transpower has under the Code, in particular as a transmission network owner." There are five SO functions that require special measures to ensure impartiality, and for each of these safeguards are in place. These include the following:

- **Procurement of ancillary services**: the SO is required to choose the best services required for ancillary needs. An example of a potential conflict could arise if the GO were to offer a BESS solution into the ancillary services market. This could be mitigated by the SOs tendering processes; however, we recognise the potential for a conflict here and so we have taken the decision that the GO does not provide any ancillary services to the SO. Consequently, this is not an issue.
- **Under frequency event causer determinations**: the SO provides advice determining responsibility for assessing causers of system under frequency events, and this includes events that may have been caused by the GO. To manage this the SO has an impartial procedure and uses an independent third party for unclear cases. The SO also has a Corporate Counsel – Compliance & Impartiality role, and one of the requirements of that role is to ensure the SO operates independently of the GO when considering the causer of under frequency events
- **Dispensation and equivalence arrangement decisions**: every asset has asset owner performance obligations, and may be granted a dispensation from the SO from having to comply or be given alternative compliance. GO has 54 currently registered but none under active consideration. In addressing the potential for conflicts for each case, the SO seeks advice from the Compliance and Impartiality Manager. The Compliance and Impartiality Manager oversees the process and ensures that the SO assesses any GO applications impartially.
- **Outage co-ordination**: the SO provides advice to the GO on coordination, timing and conditions necessary for outages. The GO may choose to still proceed with an outage, despite some risks raised by the SO. The SO can also raise concerns via the POCP assessments published. There are strict gatekeepers assigned to perform communications between SO and GO to ensure that the GO is treated in the same manner as any other participant, as well as clear guidelines and procedures for assessing this.
- **Code compliance monitoring and reporting:** the SO performs its obligations under the Code and Regulations to monitor and report on compliance with the Code, including as a participant with relevant Code obligations. Conflicts of interest are managed via a public process (GL-SD-004 Conflict of Interest.)

In addition to this, there are annual audits of key areas of potential conflict. Finally, there is a separate Board committee – the System Operator Committee (SOC) – which ensures separation at the level of governance as well.

The Authority notes that there is also a perceived risk of the potential for over-investment in transmission network assets, which may be related to the preferring of network solutions over non-network solutions, even when non-network solutions are in the best interests of consumers. The Authority notes the example of National Grid plc in the UK, which is undergoing the separation of its SO function from its GO function as a result of a real or perceived conflict of this nature. We concur with the Authority's observation that the stronger profit motives inherent to a privately owned company (as in the case of the UK). This marks a significant difference to that of the situation in New Zealand, in which we are a fully state-owned enterprise with different motives. In particular, the State Owned Enterprises Act requires us to act as “an organisation that exhibits a sense of social responsibility by having regard to the interests of the community in which it operates and by endeavouring to accommodate or encourage these when able to do so“.

Importantly, we operate in a highly regulated environment with strong safeguards in place against this sort of grid maximising behaviour. Our price-quality path regulatory regime provides the framework to ensure our revenue and expenditure are reasonably justified by the real needs of the electricity system; similarly, all major capex proposals greater than $30 million (from 1 April 2025, threshold of $20M applies up to that date) must also meet a rigorous investment test that ensures that they deliver a net positive benefit to electricity market participants.

Finally, as the Authority also notes, we are required under Part 4 of the Commerce Act to consider whether non-network solutions are a viable alternative to network solutions and there is no preferential regulatory treatment of capital expenditure versus operating expenditure. Consistent with that obligation, we have endeavoured to find non-transmission solutions that are economical. We note that, to date, we have been unable to find non-network solutions that could be economically justified. However, we expect that in the future such solutions will become economic (partly since larger scale grid projects will have higher deferral benefits); we are also committed to continue to try to make these work. For example, we are currently seeking proposals from potential providers of non-transmission solutions in the upper South Island, to help manage growing electricity use at peak times.

Our combined SO/GO model supports delivering the energy transition at pace and is appropriate for the New Zealand context.

The Authority also raises the issues of conflicts becoming potentially more relevant due to the greater complexity involved in a transition to a highly distributed net zero energy system. Great Britain (GB) serves as an example of this: a large amount of residential gas used for space heating has heightened the importance of close integration between gas and electricity through the energy transition; the presence of multiple transmission network owners and the addition of competitive tenders for offshore transmission network owners also adds greater importance to the neutrality and independence of the SO.

We acknowledge that the New Zealand electricity system could become similarly complex in the future such that a more independent SO might be justified. However, the New Zealand electricity system is different to GB in important ways. New Zealand does not have large amounts of residential gas usage, for instance, and nor do we have multiple or privately-owned transmission networks.

More importantly, the primary challenge facing the electricity sector in New Zealand is how to scale up our collective ability to deliver electrification at pace to support the energy transition. Separation of the system operator function into a new entity would result in additional complexity, cost, and duplication of effort at a time when we can least afford it.

Analysis has also identified that separation of the SO function into an ISO would lead to significantly higher costs. This cost is driven by:

- Higher asset related costs including duplication energy management systems, building fitout and other transition costs;
- Higher operating costs associated with a higher overall head count;
- A new corporate services team within the ISO; and
- Increases in other operating costs, including those associated with duplication of market systems and other Information and Communications Technology (ICT) functions and facilities leases.

There are also unquantifiable costs associated with the loss of synergies arising from these functions being delivered by a single organisation. There are advantages to having senior management and staff

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	with close working relationships between the SO and GO. Much of their collaboration is well outside of the concerns of conflicts of interest and, in fact, *supports* the kind of coordinated network planning and system operation that the Authority has, in this paper, identified as being critical.
9.	**Do you have any further views on whether this is a good time for the Authority to assess future system operation in New Zealand, and whether there are other challenges or opportunities that we have not covered adequately in this paper? Please provide reasons for your answer.**
	Overall, we commend the proactive approach taken by the Authority in this paper. We agree with the Authority's concerns regarding the importance of facilitating the integration of DER and of strengthening the coordination between transmission and distribution, especially as the DSO role emerges more clearly. The timing of this initiative is well-placed, addressing potential barriers to DER participation and enabling greater system integration ahead of material challenges. This foresightedness is crucial for paving the way towards a more flexible and resilient power system. The primary challenge facing the industry right now is the need to support electrification at an accelerated pace. While the efforts to modify rules to facilitate this transition are valuable, it's essential that these changes simplify rather than complicate the sector's regulatory landscape. The objective should be to eliminate unnecessary complexities, thereby enabling a more streamlined and efficient pathway towards rapid electrification. This point is particularly relevant in the context of separating out system operations from Transpower. As we have detailed in our response above, we need to ensure maximum coordination between all aspects of the power system in order to deliver electrification at pace. There is simply no sufficient justification for such a drastic and destabilising move at a time when we can least afford it.