Orion

31 July 2024

Transpower (System Operator)
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Submitted via email to system.operator@transpower.co.nz

Consultation Paper – Evolving market resource co-ordination in Aotearoa New Zealand

Introduction

1. Thank you for the opportunity to submit on the consultation paper '*Evolving market resource co-ordination in Aotearoa New Zealand*'.[1] This submission is not confidential and can be publicly disclosed.
2. Orion owns and operates the electricity distribution infrastructure in Central Canterbury, including Ōtautahi Christchurch city and Selwyn District. Our network is both rural and urban and extends over 8,000 square kilometres from the Waimakariri River in the north to the Rakaia River in the south; from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 225,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business (EDB).

Orion summary points

3. We have reviewed the consultation paper, and our general views are summarised in this section. Orion's specific responses to the 17 questions posed by Transpower (System Operator) as well as other feedback we consider appropriate to the consultation are set out in Appendix A.
4. Our responses address several key areas, in which we welcome further discussion, including the framing of coordinating functions, data exchange for DER, ancillary services, outage planning, and the challenges posed by emerging technologies and changing consumer behaviour.
5. We emphasise the need for greater integration of distribution-level considerations in system coordination. This includes improved visibility and data sharing across the electricity supply chain, particularly for DER participation in ancillary services. We request increased transparency in processes such as Transpower's Scheduling, Pricing and Dispatch (SPD) mechanism, recognising the growing complexity and importance of distribution networks in the overall system. Furthermore, we stress the need for the Electricity Authority to address barriers to information sharing and to carefully evaluate the potential need for a Distribution System Operator (DSO) function.
6. We look forward to further discussions on the development of a robust, flexible, and efficient market resource co-ordination scheduling and dispatch process that serves all stakeholders effectively. We remain committed to working collaboratively towards solutions that enhance the resilience and security of supply of Aotearoa New Zealand's power system.

[1] https://static.transpower.co.nz/public/bulk-upload/documents/Evolving_Market%20_Resource_Coordination_FINAL.pdf

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Concluding remarks

7. Thank you for the opportunity to provide feedback on this consultation.
8. If you have any questions or queries on aspects of this submission which you would like to discuss, please contact us on 03 363 9898.

Yours sincerely,

Connor Reich

Regulatory Lead – Electricity Authority

Appendix A

Submitter	Orion New Zealand Limited ("Orion")

Questions	Comments
Q1. Do you agree with our framing of the three co-ordinating functions?	While we broadly agree with the framing of the three co-ordinating functions, we question the necessity of separating them, as all three functions fundamentally contribute to the overarching goal of maintaining system security. Distribution-level considerations should also be integrated into these coordinating functions. The growing complexity at the distribution level, driven by the increasing prevalence of distributed energy resources (DERs), necessitates a more holistic view of system coordination that spans both transmission and distribution networks.
Q2. Do you agree with our impacts assessment of the three coordinating functions? Have we missed any trends or important information?	We broadly agree with the impact assessments of the three coordinating functions. However, we believe that several additional trends or drivers of change should be considered, as outlined in our submission to the Electricity Authority's Future System Operator consultation[2]: Changes in consumer technology are a significant factor. Smart meters with remote dynamic load control capability for hot water management are a significant development at the residential level. We reiterate the importance of considering how this technology will impact system coordination, particularly in maintaining customer service levels, ensuring accurate operational and planning forecasts, and clarifying emergency response obligations. Technological changes also extend beyond households. Process heat customers transitioning from coal to electrical or biomass solutions, and commercial consumers adopting electric vehicles and rooftop solar installations, will introduce new dynamics to the grid that must be accounted for in the impact assessment.

[2] https://www.oriongroup.co.nz/assets/Our-story/Submissions/EA/Orion-submission-future-operations-NZs-power-system-Apr-2024.pdf, pages 5-7.

	Changes in consumer behaviour also require more attention in the impact assessment. Factors such as consumer awareness, attitudes, and trust will substantially impact power system operation. We recommend incorporating insights from recent studies such as the Consumer Advocacy Council's consumer behaviour survey 2023[3] and the Resi-Flex Public Report (The Consumer and Stakeholder Lens, 2023)[4] to inform this trend. As devices become more flexible and respond to multiple value streams, forecasting their behaviour and impact will become increasingly challenging. This poses challenges for both short-term system operations, and the long-term planning timescales that inform investment. Changes in information technology (digitisation and digitalisation) must also be addressed. While most DER will be monitored and controlled through IoT devices in the long term, many flexible loads on the distribution network are currently controlled using ripple relays and are not IoT capable (e.g. hot water cylinders). The transition to data-driven, automated, and AI-based control architectures should be addressed in the impact assessment, including considerations for scenarios where data or communications are degraded or unavailable. In addition to these points, as mentioned in our response to Question 1, we recommend that the impact assessment explicitly address the coordination challenges between transmission and distribution operators, especially as the grid becomes more decentralised and complex.
Q3. What are your views on how DER owners/operators and aggregators could assist the system operator to improve load forecasting? Do any barriers exist to sharing that information?	In our submission to the Electricity Authority's Future System Operator consultation[5], we raised two key points regarding the improvement of load forecasting that we would like to emphasise again in this context: It is important to increase the visibility of DER for distributors (including its operational use), to ensure planning and operational forecasts remain accurate and use of resources can be coordinated. While distributors may have visibility of some assets, we often lack insight into its usage patterns or control by third parties. In this context, smart meter data, encompassing both consumption and network operation information, is a critical enabler for identifying network constraints and facilitating coordinated operations.

[3] https://www.cac.org.nz/our-work/surveys/consumer-behaviour-survey-2023
[4] https://www.oriongroup.co.nz/assets/Your-energy-future/Resi-Flex-Public-Report-Release-2023.pdf, pages 22-23.
[5] https://www.oriongroup.co.nz/assets/Our-story/Submissions/EA/Orion-submission-future-operations-NZs-power-system-Apr-2024.pdf, page 7.

	It is also necessary to clarify requirements for flexibility suppliers during emergency situations. This clarification is vital for maintaining power system security at both the transmission and distribution levels. We note recent discussions with the Electricity Authority regarding appropriate arrangements for distribution 'flexibility traders' to ensure visibility of flexible resources and coordination requirements, particularly in emergency scenarios. **Further feedback on the sharing of data to improve load forecasting** One of the primary incentives for sharing asset-related information is the potential for expanded operating envelopes. A more comprehensive understanding of how connections impact the network allows for the extension of operational limits. Ongoing assessment of near-real-time network condition information enables dynamic adjustments, thereby reducing conservatism in operations. Distributors should have access to different types of asset information, including both technical specifications and operational data. For photovoltaic (solar) panels installed at the residential level, we receive technical specifications from asset owners upfront as part of the connection assessment process. However, we do not receive any technical specifications for other types of assets, such as EV or load data. For all assets, accessing operational information is more challenging. We have recently begun utilising third-party collected smart meter data, though we are not yet accessing data from inverters. We do not receive technical data for residential EV charge points and note that the majority of residential EV charging is from 3 pin wall sockets rather than EV charge points. Orion has concerns that the System Operator may seek additional information from distributors without rule changes providing clarity on how that data should be collected, paid for, and distributed. Furthermore, we are concerned about future expectations of the System Operator regarding distributors' ability to collate and supply data that should be provided by other parties, such as retailers or aggregators, who have more direct access to this data. There are also questions about the long-term practicality of the System Operator assimilating all this information from within a distributor's boundary. This raises the possibility of needing a Distribution System Operator (DSO) function operating across distributor boundaries, to ensure that aggregated non-conforming loads can be reported accurately. Implementing such a function would require distributors to have better access to data currently not available.

	Barriers to information sharing There are currently limited incentives for DER asset owners to provide data. The process may impose additional system and personnel overheads, potentially resulting in extra costs. Commercial sensitivity concerns, particularly for proposed systems, may also contribute to reluctance in sharing information. The regulatory framework presents challenges, with no clear definition of DER in the Electricity Code and no inclusion of aggregators' responsibilities. We support adding definitions for both DER and aggregators, and advocate that all market participants should be subject to consistent requirements, including those related to BESS/batteries, EVs, solar, wind, and other emerging technologies such as hydrogen electrolysers. A rule change is necessary to mandate the sharing of data, especially for behind-the-meter devices. Currently, there is no required sharing of such data, necessitating the purchase of this information from third parties by distributors. Limited understanding or awareness of what is controlled by the retailer or aggregator, and why, impacts our ability to fully understand the impact on load profiles. Additional barriers and enablers from the perspective of 17 flexibility stakeholders (identified through interviews and surveys) were published by Orion and Wellington Electricity in their Phase 1 Resi-Flex Project report in 2023.[6]
Q4. What are your views on how the market should handle intertemporal constraints on assets? What options, if any, should the system operator investigate?	The Electricity Authority should have input and rule-making capability over the market at every point in the electricity supply chain, including over the best methods on handling intertemporal constraints on assets. The Authority should not be limited primarily to the generation, transmission and retail levels. It is important to recognise that generation or transmission issues often translate into network problems for distributors. We advocate for increased transparency regarding Transpower's Scheduling, Pricing and Dispatch (SPD) mechanism, with particular emphasis on its optimisation challenges and formula. Market participants and stakeholders should have a clear understanding of how optimisation occurs, through well-defined rules and regulations, in order to foster a more informed market and more effective decision-making that enables the right outcome for end users – reliable and efficient electricity supply.

[6] https://www.oriongroup.co.nz/assets/Your-energy-future/Resi-Flex-Public-Report-Release-2023.pdf, pages 18-23 and 38-39.

Q5. How should "tie breaker" situations be resolved for multiple competing offers?	While Orion does not have specific comments on the resolution of 'tie breaker' situations for multiple competing offers, we would like to raise related concerns regarding the broader implications of pricing dynamics on our network. We are particularly interested in better understanding the impact of negative pricing scenarios and their effects on demand within Orion's network. For instance, in a situation where negative pricing occurs, we anticipate that retailers would respond, subsequently affecting nodal pricing. If this coincides with an increase in solar generation, it could potentially lead to unanticipated demand forecasts, resulting in unintended consequences for the local distribution network. To address these challenges, Orion sees the benefit of creating 'blocks' of assets, such as aggregated rooftop solar installations. This approach could enable more effective management of these distributed resources, allowing for the shifting or curtailment of additional supply[7] when necessary to maintain system stability and optimise network utilisation. Furthermore, it is crucial to examine how optimisation processes can account for scenarios involving $0 cost energy, particularly in the context of regional constraints. We suggest that the resolution of such situations should prioritise minimising network impact, ensuring the most efficient and stable operation of the distribution system.
Q6. What are your views on the frequency and duration of the schedules? Please specify the changes you would recommend making to the frequency and duration of the schedules.	Orion does not have specific comments on the frequency and duration of schedules, but we would like to raise related concerns regarding how these schedules might interact with our ability to dispatch assets for purposes that may differ from those outlined in the proposed scheduling framework. It is unclear whether such dispatches would be covered under these schedules or if they would be considered separate items.

[7] It's important to note that implementing this strategy will require changes to connection agreements, and the development of communication systems with the resources we wish to control. This indicates that significant preparatory work needs to be completed before the benefits of these systems can be fully realised.

	We also question whether our ongoing demand management tools, such as hot water ripple control operations, should fall under these forecasts, and if so, how they would be integrated. This consideration raises an important point about the potential future role of a DSO function. While the potential need to coordinate local demand management tools with broader system schedules might suggest a DSO model, we believe it's important to examine whether this model is necessary or appropriate for the New Zealand context. Further work is essential to fully understand the implications, potential benefits, and alternatives to transitioning towards a DSO model, ensuring that any changes to our current system are truly warranted and beneficial.
Q7. What market co-ordination functions could be incorporated into the market design to reduce the need for discretion? e.g. inter-temporal scheduling and dispatch could allow for slower-ramping plant to be dispatched earlier compared to a single period dispatch model.	No comment.
Q8. Do you agree with the benefits we have laid out and the recommendations we have made concerning data exchange for DER? Please share any other ideas or thoughts you have regarding DER data exchange.	Yes, we agree with the benefits outlined regarding data exchange for DER. DER data exchange and availability will improve distributor opportunities to economise on network performance outcomes and efficiencies of networks.

	As stated in our response to the Electricity Authority's issue paper on updating the regulatory settings for distribution networks[8], Orion considers updating Part 6 of the Code to include data sharing capability to be a priority. Access to real-time smart meter data and improved DER visibility needs to be given higher priority by the Electricity Authority. The more visibility distributors have on their network about congestion and power quality, the better they can forecast planning of flexibility services, replacement, renewal, and system growth. It's worth noting that this improved forecasting capability at the distribution level would also benefit the System Operator, particularly as distributors becomes better at near real-time forecasting. Distributor visibility should be prioritised by the Electricity Authority within the next three years to facilitate effective network management planning. This visibility is crucial for assessing the impact of all DER installations, ensuring network stability and safety, and understanding the impact of export energy on the network. The Electricity Authority should mandate cost-effective access to DER data. This information, which often sits behind the meter, needs to be made accessible to allow distributors to use it for modelling purposes. Finally, there is an opportunity to standardise asset data formats to ensure consistency and interoperability across the sector. This standardization would greatly enhance the efficiency and effectiveness of data exchange for DER.
Q9. What are the most pressing scheduling and dispatch issues you see affecting participation by batteries and DER?	While we agree with the regional aggregation issue, we believe the framing of this question may be too narrow. We suggest that a more beneficial approach would be to examine what future DSO or EDB functions might look like, and how these would interact with the System Operator. It's our view that it may not be optimal for the System Operator to extend its reach into regional distribution areas that could potentially be better managed by EDBs or the DSO function. Local management of DER and batteries could provide more agile and context-specific responses to grid needs.

[8] https://www.oriongroup.co.nz/assets/Our-story/Submissions/EA/EA-feedback-on-issues-paper-updating-the-regulatory-settings-for-distribution-networks-Mar-2023.pdf, page 3.

Q10. What are your views on the issues we have raised in relation to ancillary service products? What options should be considered to address these issues?	We agree with the issues raised in relation to ancillary service products. It is critical that the System Operator can procure what is needed for security of supply. However, we note that the current tools and settings supporting ancillary services should undergo a wider review. This review should not only address current challenges, but also offer the provision of services that could be useful in terms of enabling EDBs to participate and pass on benefits to their consumers. We suggest exploring the possibility of mandating battery installations alongside all grid-scale solar installations. This could be complemented by implementing cash rewards or incentives for stable and predictable performance. Such an approach could significantly enhance the stability and reliability of DER within the system. There may be value in investigating the potential for aggregating all small-scale solar installations across the network. This aggregation strategy could provide a more manageable and predictable resource for system operations. However, we emphasise that storage solutions would be necessary to ensure system stability in this scenario. We strongly advocate that if DER are to participate in ancillary services, distributors must have visibility of this participation. This visibility is crucial as it directly impacts our forecasts and observed behaviour on the network. Without this information, our ability to effectively manage the distribution network and plan for future needs could be compromised.
Q11. Do you believe there is a case for the system operator exercising limited discretion in ancillary service procurement to support greater innovation and participation? How should the system operator go about doing so?	We disagree that the System Operator should be allowed to exercise limited discretion or obtain waivers in ancillary service procurement to support greater innovation or participation. Our view is that such initiatives should be left to the distributors to get involved. The primary focus of the System Operator should be on prioritising security of supply, rather than conducting trials or experimental procurements.

	If changes are to be made to ancillary service procurement processes, we strongly believe that distributors should be included in these discussions and decision-making processes. This is particularly crucial if increased participation is expected from distribution-connected assets. Distributors have a unique understanding of their networks and the potential impacts of new technologies or procurement strategies. Our involvement would ensure that any innovations or increased participation in ancillary services are implemented in a way that maintains network stability and reliability, while also supporting broader system goals.
Q12. Do you agree with our framing of the challenges we expect to face delivering our role within the outage planning process? Please share your reasoning.	While we generally agree with the framing of the challenges expected in delivering the System Operator role within the outage planning process, we would like to highlight some additional considerations, particularly regarding new connections. The challenges associated with new connections are heavily dependent on both the size of the connection and its location. We believe there is a significant risk for rural areas to experience a drop in security of supply as the system evolves. This is a crucial point that warrants careful consideration in outage planning processes. The system is not able to operate effectively during outage planning, when adhering strictly to N-1 security standards. This presents a considerable challenge, especially when connecting new assets. We propose that security rules should be modified to allow for greater flexibility. Specifically, we suggest changing the grid-scale DER security standard from N-1 to N, with the provision to temporarily operate at N security when necessary, such as during the connection of new assets. This approach would provide the flexibility needed to manage the system more effectively during these critical periods. We believe that incorporating this flexibility into the outage planning process would significantly enhance the System Operator's ability to manage the challenges outlined, particularly in relation to new connections and maintaining security of supply across diverse geographical areas.
Q13. What, if any, impacts to your business do you see from the expected increased uncertainty of outage planning in the future? NB answers may be used to build the business case for changes to outage planning.	The increased uncertainty in outage planning presents several challenges for Orion. The current market framework does not adequately incentivise planned outages, and there's no certainty for outages planned a year in advance. This necessitates more work to plan long-term outages for customers.

	Orion is also concerned about the potential shift from ripple demand management to 'flexibility' demand management of hot water cylinders. If the System Operator requests a planned outage, we may be required to pay third parties/aggregators that control the load to comply with the outage. This puts us in the position of paying for flexibility, which could significantly impact our operational costs.
Q14. What, if any, operational changes do you think are needed to support outage planning in the future? E.g. use of probabilistic supply and demand analysis, consideration of 'new' system characteristics such as transient stability and system strength etc.	Going forward, we believe better communication between Transpower (as System Operator), and distributors will be crucial. Currently, for embedded generation and DER over a certain size on our network, asset owners are required to notify Transpower when outages are needed. We suggest removing this intermediary step to allow for more direct and efficient communication between all parties. We also question whether the current transfer of risk during a planned outage is appropriate. For instance, if the System Operator has a planned outage and we load another part of our network more heavily, resulting in an equipment failure, are we still responsible for SAIDI/SAIFI? If so, we believe there's a need to explore how we could more appropriately distribute the risk of planned outages with the System Operator.
Q15. What are your thoughts on the concept of 'locking-in' outages? If you think there is value in progressing with this idea please share your thoughts on how you would see it working in practice.	There would be value to Orion if Transpower could clearly define what 'locking-in outages' means to the System Operator. Is it the current system, where an outage date and alternative date are locked in as part of the annual plan, or something different? If a different system is proposed, Orion requests that Transpower share further detail on what they define as 'locking in' planned outages. We also seek clarification on whether daily curtailment at a smaller GXP equals a planned outage.
Q16. Do you agree with our framing of the need to improve data and information sharing as it relates to outage planning? If not, please share your reasoning.	Yes, we agree with the framing of the need to improve data and information sharing as it relates to outage planning. However, we'd like to raise some additional points: • Data collection and sharing for its own sake is not useful. It's critical to understand both what specific data is needed, and what outcomes are desired from that data for it to be truly valuable. This understanding ensures that the data collected is relevant, actionable, and contributes meaningfully to improved outage planning. • Secondly, it's important to clarify who will bear the cost of data collection and sharing. This is a crucial consideration as it can significantly impact the feasibility and sustainability of any proposed data sharing initiatives.

	• To illustrate these points, we note that Orion has been providing Upper South Island sheddable load data to the System Operator since 2009. However, this data has only recently started being used again by the System Operator following the 9 August 2021 event. This example underscores the importance of distributors knowing how and when their data is being used, to ensure it is provided to the right people, at the right time, in the right format, to solve the right problem. • We also question the requirements of obligated parties – where those asset owners' outages could impact system security. We suggest developing a threshold that assesses both the materiality and the location of potential impacts on the System Operator.
Q17. Do you believe the best way to progress increased data and information sharing, the method of exchange, and who must provide it, is through regulatory changes or via guidance notes and industry agreements? Please share your reasoning.	We believe that progressing increased data and information sharing is best done through regulatory changes. We would prefer that the Electricity Authority establish data and information sharing regulations that strike a balance between consistency and adaptability across the sector. These regulations should mandate that all industry participants (including retailers and aggregators) must share relevant data. It's important that data sharing is also made affordable, with clear cost structures that enable all industry participants to access and use the data effectively, ultimately reducing costs for consumers. The regulations should require robust security measures to protect sensitive information, while promoting equity in data access across different sector participants. This balanced framework would ensure fairness, security and affordability in data sharing, while providing the necessary information to improve system operations and planning. It would foster an environment that supports innovation and efficiency, allowing for appropriate adaptability in implementation methods, while maintaining consistent data quality and accessibility standards.