Orion

3 July 2025

Electricity Authority
PO Box 10041
Wellington 6143

Submitted via email to taskforce@ea.govt.nz

Consultation Paper – Rewarding industrial demand flexibility

Introduction

1. Orion welcomes the opportunity to submit on the consultation paper 'Rewarding industrial demand flexibility: Issues and options paper'.[1]
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 230,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business (EDB).
3. Orion's Control Period Demand (CPD) pricing represents one of New Zealand's strongest commercial and industrial (C&I) consumer demand flexibility incentive programmes. CPD does not require a contract by the C&I consumer to participate, and it is the consumers' choice as to whether they respond to any (or every) control period. Through this mechanism, we provide clear price signals that enable C&I customers to reduce their network charges by shifting load away from peak periods. At current prices, our major C&I customers will save about $134 in annual charges for every 1kW reduction during control periods.[2]
4. Orion participates in the Upper South Island (USI) Load Management Group, alongside Alpine Energy, Buller Electricity, EA Networks, MainPower, Marlborough Lines, Network Tasman, and Westpower. This group collectively shifts an aggregated 140MW of flexible hot water demand from network and transmission peaks via ripple. This delivers substantial benefits to member EDBs, Transpower (as Grid Owner), the System Operator, the wider energy system (including retailers), and ultimately customers through reduced infrastructure costs.[3]

---

[1] Rewarding industrial demand flexibility

[2] Refer to Delivery pricing for major customer connections – Summary for further details on CPD.

[3] Benefits include: delaying investment and reduced transmission charges for EDBs; reduced or delayed transmission investment needs; supporting grid voltage stability and improving the System Operator's management of transmission outages, and the wider energy system through lower wholesale prices for retailers.

5. Orion also operates one of New Zealand's largest network residential hot water demand flexibility programmes. Our ripple signalling infrastructure enables us to shift approximately 30-60MW from peak demand via fixed time signals, and 52MW from peak via our Peak control.[4] Residential consumers save $52 on their fixed charges, and up to $138 on their variable charges per year.

Executive summary

6. While Orion agrees in principle that it is important to increase C&I demand flexibility participation, and reward that participation appropriately, Orion does not support the Industrial Demand Flexibility issues and options paper as proposed.
7. Orion submits in support of the Task Force's proposal to develop a standardised product for demand flexibility.[5]
8. Orion submits that the Authority continues to mischaracterise the demand flexibility landscape in New Zealand by consistently overlooking the most readily available, cost-effective and efficient resource: residential hot water demand that EDBs have the ability to flex, which has growing potential for shared control by retailers. EECA estimates indicate over 1GW of demand flexibility is available through EDB-controlled ripple, dwarfing the ~170MW of potential C&I flexibility identified by the Authority in this consultation paper.[6]
9. The Authority's consultation (paragraphs 2.31 – 2.33) acknowledges sector concerns that demand response is currently underutilised, and emphasises the importance of "*using all available tools to promote reliability*." The Authority specifically recognises ongoing concerns "*that demand response is currently underutilised"* and expects "*the potential for demand flexibility to increase*." Yet despite these acknowledgments, the Authority proposes developing new market mechanisms before making full use of existing, and proven, EDB load management capabilities. Managing hot water demand has the same net effect as bringing on additional generation. Generators that bring on additional generation during peak periods are paid for meeting that need, yet EDB demand management receives no compensation despite providing the same system benefit. The approach of creating new tools while ignoring the 1GW of existing flexible load is inefficient and may not align with the Authority's stated objectives.[7]

---

[4] Orion's ripple signalling system includes 43 injection plants located across 26 urban and 17 rural substations. Approximately 85% of residential ICPs are in our controlled billing category, which represents approximately 168,000 ICPs.

[5] Orion has previously submitted in support of the Task Force working with industry to develop standardised flexibility service contract templates for distributors, traders and aggregators. See Orion's submission on 2A and 2BC initiatives, paragraph 6a.

[6] Ripple Control of Hot Water in New Zealand, EECA, September 2020.

[7] We note that the Authority has indicated in recent decision papers that it considers "*the use of controllable load during grid emergencies is a suitable interim solution while new technologies roll out and longer-term solutions are developed*" (Update to scarcity pricing settings, paragraph 3.96). It also indicates that "*...potential growth in demand response services, would likely strengthen wholesale market competition*" (Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system, Executive Summary). While there has been significant recent interest by retailers in exploring shared load control on our network, only approximately 30% of residential meters can enable this form of control. As outlined previously, 85% of Orion's residential ICPs are on a controlled billing tariff, which demonstrates that there will be a measurable delay before retailers (or aggregators) are able to effectively provide demand control capabilities at scale and in a timely way needed by some applications e.g. emergency response.

10. The value of EDB load management extends well beyond network benefits. A 2018 report found that wholesale prices in the USI would increase during peak periods by up to 87.2% if USI Load Management disappeared. [8] This increase is likely higher given recent wholesale price volatility. Despite providing this substantial market benefit, the USI Load Management Group receives no explicit (payment) or implicit (pricing) signal from retailers or Transpower for operating load management on their behalf. The implicit pricing signal from Transpower post-TPM is severely muted, with limited visibility on future cost avoidance and only providing visibility when constraints are close to binding. The ability to explicitly quantify the value is made more difficult by the complexity of the TPM.

11. Orion submits that current barriers to C&I participation need to be better understood and addressed before creating new market mechanisms. Our customer feedback consistently identifies resourcing, education and awareness, and business operational productivity as key barriers. While Orion is working to address these issues locally via an internal C&I flexibility project, we note that the Authority has an opportunity under the Electricity Act 2010, clause 16(f) to provide "*market-facilitation measures (for example, providing education)*" that could help address these barriers. We encourage the Authority to prioritise understanding and resolving these barriers through targeted education and support programmes before introducing additional market complexity.

12. Orion submits that the nascent nature of the flexibility market currently poses a significant impediment to EDBs implementing non-network solutions at sufficient scale to effectively defer or avoid more traditional 'poles and wires' investments. As outlined in Orion's recent submission to the Commerce Commission on Aurora's CPP to DPP4 transition, non-network solutions face significant market development challenges, including the failure in late 2024 of a flexibility trader.[9] The market reality is that only 3.5% of residential ICPs, nationally, have distributed energy resources installed, and of those, only around 13% have batteries (representing only 0.5% of total residential connections). Our recent Lincoln Flex Trial demonstrates this supply constraint: insufficient existing flexible assets in the target area prevented scaling to required levels to defer the necessary investment, and offering significant incentives did not attract consumer investments in DER at the pace needed.[10] We are not aware of mature aggregation business models in New Zealand that can be contracted to provide reliable services at useful scale. Additional regulatory requirements aimed at flexibility purchasers will achieve limited results when the primary challenge exists on the supply side, with insufficient market-ready flexible assets and established commercial aggregation services for EDBs to contract with.

---

[8] IEGA - List of distributed generation eligible to receive ACOT, Upper South Island

[9] See Orion's submission to the Commerce Commission for further commentary on these challenges. Customer education is critical for market development, as consumers need to understand what a decentralised electricity system looks like and how they can benefit from participation. Please see Orion's submission on the decentralisation green paper for further commentary on the role of the Authority in educating consumers.

[10] Orion is actively working to address these challenges, through initiatives like an EECA-funded pilot project, which will provide subsidies for retrofitting smart connectivity to existing household devices, with the aim to reduce peak demand by up to 1.6MW in a selected network area.

13. Orion submits that any demand flexibility framework must recognise operational realities, and explicitly prioritise grid and networks security as a foundational principle. Load restoration is a critical component of any load control on a network. Maintaining secure and reliable operation of both transmission and distribution networks is a precondition for all other market and consumer benefits. While turning off load typically poses minimal network concerns, coordinated (or aggregated) restoration in response to wholesale market or other pricing signals may cause network issues. [11] Coordinated Load Management Protocols will be essential to manage these risks. We note the Electricity Networks Aotearoa is developing a common LMP framework in conjunction with retailers and distributors to address these coordination challenges.[12] We encourage the Authority to explicitly support the development of this work.

14. Finally, Orion disagrees with the Authority's framing of "implicit" versus "explicit" demand flexibility (Types 1 & 2). The Authority should align with industry terminology and refer to these mechanisms as "Pricing" versus "Payments" to avoid confusion and better reflect the actual mechanisms involved. The current framing is confusing because both pricing and payments can be delivered as either explicit or implicit signals. For example, "free hours of power" is a pricing mechanism but provides a very explicit signal to consumers about when to shift load. The key distinction is not whether the signal is explicit or implicit, but whether the mechanism uses pricing signals to incentivise response or direct payments for demonstrated flexibility.

15. Our specific responses to the questions posed by the Task Force are set out in Appendix A.

Concluding remarks

16. Orion submits that the Authority should focus on optimising existing tools that demonstrably deliver existing consumer benefits, rather than creating new mechanisms that may see little-to-no uptake. We strongly urge the Authority to consider enabling appropriate recognition for the approximate 1GW of existing EDB-controlled demand flexibility, for the benefit of New Zealand.

17. We strongly encourage the Authority to coordinate with relevant workstreams, including the FNF Load Management Protocol project, to ensure coherent system-level outcomes.

18. We strongly suggest that the Authority prioritise education and support programmes to address identified barriers.

19. Orion supports the ENA's and Vector's submissions in principle.

20. This submission is not confidential and can be publicly disclosed.

21. 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

---

[11] As noted by Vector in its submission on Potential solutions for peak electricity capacity issues, participants can pursue commercial opportunities but must ensure they do not cause damage, loss of supply, or power quality issues for network and other consumer's assets.
[12] https://www.ena.org.nz/our-work/working-groups-and-forums

Appendix A

Submitting organisation	**Orion New Zealand Limited ("Orion")**
Contact person	**Connor Reich**

Questions	Orion's response
Q1. Do you agree with our approach of focusing on industrial demand flexibility as an early initiative to enable demand flexibility more broadly? Why/Why not? Do you have any information to indicate that demand response from other consumer types may be more readily accessed?	Orion agrees that C&I customers have some of the lowest cost flexibility that is currently installed but not being utilised. For reasons outlined in our covering letter Executive Summary, C&I demand flexibility represents the second easiest form of demand flexibility currently available in New Zealand, after residential hot water load control. However, Orion submits that the Authority's approach overlooks the most readily available resource. Residential hot water load controlled by EDBs represents over 1GW of immediately available demand flexibility, compared to ~170MW of potential C&I flexibility. Through our ripple control system, we shift approximately 30-60MW from peak load via fixed time signals (100-190MW when restored) and 52MW from peak via our Peak control (174MW when restored). As shared previously, 85% of Orion's residential ICPs are on controlled billing (~168,000 connections) compared to only ~30% of ICPs with smart meters eligible for shared control by retailers (~60,000).[7] The USI Load Manager manages load that is valuable to Transpower, yet Transpower does not make that value explicit to USI consumers. A 2018 report found that USI wholesale prices would increase during peak periods by up to 87.2% if USI Load Management disappeared. Managing hot water load has the same net effect as bringing on additional generation - generators that bring on generation get paid for meeting that need, yet when the USI sheds its hot water load, it receives no payment for the service. Orion would like to see rewards from USI Load Management shared with consumers more efficiently, which requires explicit price signals from Transpower and through retailers.
Q2. Do you agree with our estimates of the potential industrial demand flexibility capacity available in New Zealand currently and into the future? Why/why not? Do you have any evidence to support a materially different estimate?	Orion has no specific comments on the capacity estimates provided.
Q3. Do you agree with our focus on intra-day demand flexibility for this initiative? Why/why not? What other approach would you suggest?	Orion submits in support on the focus on intra-day flexibility as appropriate for industrial demand response. Please refer to our submission to Transpower's Security of Supply Forecasting and Information Policy (SOSFIP) Review Issues Paper 2025

Questions	Orion's response
	which noted the need to also consider a resource (energy) adequacy reserve facility as a solution to manage seasonal energy shortages.[13]
Q4. Are there any other ways that currently enable industrial demand flexibility in New Zealand?	Orion notes that our Control Period Demand (CPD) component of our major customer price category is a strong demand flexibility incentive. Through this mechanism, 36 C&I customers respond to more than 90% of signals, achieving meaningful load reduction of approximately 20MW. Every 1kW reduction during control periods saves customers $134 in annual charges. Our CPD operates during the winter season (May through August) when network peaks typically occur. We forecast to signal 80-100 hours of control periods annually, with individual periods typically lasting no more than 2 hours in a 5-hour period. Control periods are triggered when network load would exceed predetermined thresholds, and we provide multiple notification methods including ripple signals, text messages, and email alerts to enable customer response. Major customers are split between two control period groups to stagger load changes and manage network stability. Customers do not need to respond to all control periods to receive benefits - we calculate their average load reduction across the season. This flexibility in response, combined with advance notification and financial incentives, represents a mature and effective demand response mechanism. Despite these features, uptake remains challenging, indicating that barriers beyond incentive levels prevent broader participation. Additionally, our Irrigation Interruption Scheme provides approximately 5% discount on capacity charges for customers who participate in capacity emergency response, offering another avenue for demand flexibility participation. For further details on CPD and our Irrigation Pricing Schemes please refer to Orion's Irrigation pricing summary and FAQ and Orion's Pricing Policy.
Q5. Do you agree with our description of the barriers affecting the provision of industrial demand flexibility? Why/why not? Are any other barriers relevant to the provision of demand flexibility from other consumer types?	Orion submits that the Authority's description of barriers is incomplete. While the Authority identifies some barriers, it does not adequately address the education and awareness barrier. Orion notes that the Authority has an opportunity under the Electricity Act 2010 to provide market-facilitation measures, including education, that could help address these gaps.[14] Orion has conducted customer engagement to identify other specific barriers that limit, or prevent, C&I customers from responding to Orion's control periods. These include:

[13] Orion submission - Security of Supply Forecasting and Information Policy Review, response to Q8.
We note that the gentailers have signed a terms-sheet to develop a strategic energy reserve centred on the Huntly power station. See https://www.energynews.co.nz/news/security-supply/821347/gentailers-sign-term-sheet-huntly-energy-reserve for further details.
[14] Electricity Industry Act 2010, clause 16(1)(f).

Questions	Orion's response
	• Little to no understanding, by the consumer, about the "size of the prize" for providing flexibility • Limited risk appetite and uncertainty about how flexibility can impact operations or service levels • Flexibility not generally considered in energy management plans • Limited awareness of CPD by facility managers and low priority/lacking resources to assess and support uptake • New facilities being commissioned without CPD response, or other forms of demand response, being considered in design, energy or financial planning • Perception that load-shifting means higher consumption, which could offset CPD benefits Additionally, Orion notes significant resource constraints. Many major C&I customers have minimal dedicated energy management resources (for example, we are aware of a major industrial that has only one person responsible for energy management). Equipment availability is a known barrier, as demand flexibility requires appropriate equipment that often isn't available or installed. There is an opportunity for EECA or other government bodies to subsidise installation costs and put in flexible equipment. Technical or building standards could also require flexible equipment installation.[15] Orion submits that these existing barriers that prevent uptake of demand response must be addressed before the Authority creates new market mechanisms.
Q6. Do you agree that existing incentives and contracts for demand flexibility are resulting in inefficiently low levels of demand flexibility?	Orion disagrees with this characterisation. Our pricing provides significant incentive (approximately $133k/MW) to shift load, yet only a small subset of qualifying C&I customers choose to participate. This suggests a different perspective on the Authority's assertion that incentives are insufficient. Orion submits that EDBs are missing clear signals from Transpower and retailers. While our CPD signal manages load on our network, avoiding transmission costs and investment, retailers could pass on cost savings, but it is not clear that this occurs in every case. Building on our response to Q5, the Authority should investigate why current incentives and contracts are not working (e.g. existing barriers) and address the root cause, rather than establishing new market products that may have little to no uptake.
Q7. Are you aware of any additional barriers to enabling	Orion notes that industrial customers may not be sufficiently informed to understand their options and optimise their participation across multiple

[15] Orion previously raised this in our response to the Energy Competition Task Force initiatives 2A & 2BD. [Orion's submission on 2A and 2BC initiatives], paragraphs 6d and 6e.

Questions	Orion's response
more industrial demand flexibility?	potential value streams. See our response to Q5 for further discussion on this point. More broadly, the nascent nature of New Zealand's flexibility market prevents the development of demand flexibility at scale across all consumer types, not just C&I. The market lacks sufficient distributed energy resources and established aggregation services for EDBs to procure meaningful non-network solutions and defer network investment. Our Lincoln Flex Trial demonstrates how this barrier affects residential demand flexibility development. Despite offering a 51-cent buy-back rate for peak periods (substantially higher than market rates), we achieved only 0.72% household participation (in the target area) and could scale to just 100kW of our 500kW target. This shows that even when EDBs make a best endeavours attempt to procure demand flexibility capability to defer network investment in a targeted area, insufficient existing flexible assets in target areas prevent effective scaling, regardless of financial incentives offered.[16] Orion is working to address these market development challenges. However, until the flexibility market matures with sufficient assets and services available for procurement, all forms of demand flexibility will potentially remain constrained regardless of the market mechanisms created. [17]
Q8. Do you agree with our vision for industrial demand flexibility? Why/why not?	Orion agrees that demand flexibility must meet the criteria of value exceeding cost, and cost being less than alternatives. EDBs already operate under these criteria - we implement demand flexibility (including ripple) only when it meets these tests.[18] Orion notes that our existing ripple control system already meets the Authority's definition of efficient demand flexibility. As stated in paragraph

[16] As outlined in Orion's submission to the Energy Competition Task Force initiatives 2A and 2BC, the Lincoln Flex Trial was designed to test whether residential demand flexibility could defer network investment in a real-world setting. We sought to defer the upgrade of a 12MW transformer at Lincoln by procuring 500kW of demand response from residential solar + battery systems. The trial was reliant on either pre-existing consumer installations, or on consumers willing to install distributed energy resources at their own cost to take advantage of the buy-back rate. The limited number of existing installations and high upfront costs preventing new participants meant that insufficient flexibility was available to defer even a modest network investment, which highlights the current market constraints facing non-network solution procurement.

[17] We are encouraged to see recently announced EECA and EDB scale demand flexibility trials, which includes retrofitting 'smart' capability into existing consumer devices. This effectively enables EDBs, working with Government and consumers, to target investment to build market capability. See: Orion's announcement and Counties Energy announcement for further details.

[18] Before committing to traditional ripple control investment for demand response, Orion first assesses whether demand response is required at the specific substation or GXP. If demand response is required, we then evaluate the most cost-effective and reliable method to deliver it – comparing a traditional system, with market-based demand response solutions. Our decision process aligns with the Authority's view on efficient demand flexibility (paragraph 6.3 of the consultation material). That is, that the value of demand flexibility to consumers (in aggregate) must exceed its cost, and that the cost of providing demand flexibility must be less than the cost of alternative solutions. In practice, we find that current market and regulatory arrangements do not incentivise the development of new flexibility capability by consumers, which limits our options to what is already available.

Questions	Orion's response
	6.3 of the consultation, efficient demand flexibility occurs when "*the value of the demand flexibility to consumers (in aggregate) is greater than the cost*" and "*the cost of the demand flexibility is less than the cost of alternatives*." Our ripple control system delivers over $19.5m in annual savings for consumers through network investment deferral.[19] Orion notes that the Authority's view on how to give effect to this demand response vision is "*so long as it provides net benefits to consumers, we are agnostic as to how demand flexibility is provided…*"[20] However, we observe an inconsistency in practice: the significant demand response already managed by EDBs, is not always fully recognised or efficiently utilised within current market arrangements. USI Load Management, and local load management on our network, already deliver an efficient outcome for all sector participants, yet there are limited payments (explicit type 2) or price (implicit type 1) signals from both retailers and Transpower to incentivise or reward this flexibility.[21] As a result, the system and market are not making full use of existing, and proven, demand response resources. Orion submits that there is an opportunity to address this by potentially requiring EDBs to incorporate wholesale market signals into control periods. Currently, these signals often align with peak demand in our network and USI region, though this may change overtime as we move into a more intermittent renewables electricity system. More generally, we see value in exploring a range of options to better integrate EDB-managed demand flexibility with wholesale market conditions. This could include considering how EDB-managed demand flexibility might be incorporated into wholesale market operations across all periods – not just during scarcity periods. We note that this should be viewed as an interim step, as retailers and aggregators continue to expand their own load control systems and begin to control load that can be offered into both the wholesale and ancillary services markets. In the meantime, leveraging these established resources now will support a more flexible and efficient electricity system for consumers, while the market and technical capabilities of participants continues to evolve.
Q9. Do you believe that this vision is applicable to other	Orion submits that the vision is applicable to all forms of demand flexibility, and to flexibility more generally.

[19] Further details about the ongoing costs of maintaining our ripple load control system, which defer investment for both Orion and Transpower (via our participation in USI Load Management), are included in our Asset Management Plan: over the 10-year period, replacement CAPEX for load control systems totals $10,998,000 (see "Load Management" in Table 10.2.3), while network OPEX amounts to $4,153,000 over the same period (see "Load Management" in Table 10.2.4). This demonstrates that the costs of providing demand flexibility via ripple control remain well below the value delivered to consumers.

[20] Rewarding industrial demand flexibility, paragraph 6.6(e)

[21] As outlined previously, a 2018 paper found that if USI Load Manager ceased operation, wholesale market prices in the USI would increase in peak periods by up to 87.2%. See IEGA - List of distributed generation eligible to receive ACOT, Upper South Island for further details.

Questions	Orion's response
forms of demand flexibility, or to flexibility more generally?	
Q10. Do you agree with our view that demand flexibility providers should be able to receive payment for providing flexibility services that exceeds avoided energy costs, provided the demand response is efficient (as defined)? Why/why not?	Orion submits that we support Vector's submission on this question.
Q11. Do you believe that a different level of payment would be appropriate? Why/why not?	Orion submits that we support Vector's submission on this question.
Q12. Do you agree with our proposed guiding principles? Why/why not? Are other specific considerations which you believe should be included in the evaluation framework?	Orion submits in support of the proposed guiding principles, but raises the below concerns for the Authority to consider: We caution that the Authority must carefully consider wholesale market manipulation risks arising from vertical integration and bilateral market power, where four companies generate both 80% of electricity and hold approximately 85% of the residential retail market (Principle: *Enable efficient operation of the electricity industry and minimise costs for consumers in the long run*). The Authority's long-term vision of transitioning demand control from EDBs to retailers would further concentrate both supply-side and demand-side market power within these same entities, potentially amplifying concentration risks. When companies control both generation and demand response resources, they may have opportunities to strategically coordinate these assets in ways that could affect market outcomes. For illustration, a vertically integrated company with excess generation capacity relative to its retail book could theoretically benefit from strategically managing flexible demand during periods of forecasted high wholesale prices - turning demand on during high-price periods to further inflate wholesale costs for all participants while benefiting their generation portfolio. Such gaming behaviour could undermine the market efficiency objectives the Authority seeks to achieve and represents a systemic risk requiring explicit safeguards. While the proposed guiding principles cover a wide range of outcomes, Orion notes that an explicit reference to both grid and network security is missing. Maintaining the secure and reliable operation of both the transmission and distribution networks is fundamental to the electricity system, and must remain a central consideration in any future demand flexibility product, as security and reliability of supply is a precondition for all other market and consumer benefits. We urge the Authority to explicitly include grid and network security as a core principle and outcome to guide the development and implementation of future demand flexibility initiatives. Orion submits that we support Vector's submission on this question.

Questions	Orion's response
	Orion submits that we support Unison and Centralines comment regarding the development of a Load Management Protocol. We strongly recommend that the Authority engage with, and support, the Future Network Forum's Load Management Protocol project, which is being led by Electricity Networks Aotearoa. This project is focussed on coordinating the use of controllable load, which includes industrial demand flexibility, between distributors and retailers during, and in the prevention of, system emergency events.
Q13. Do you agree with our view that there is currently insufficient potential industrial demand flexibility to justify the establishment of new market mechanisms or platforms other than the proposed ERS and standardised demand flexibility product?	Orion submits that we agree there is currently insufficient industrial demand flexibility to justify creating entirely new market mechanisms or platforms. We strongly recommend that the Authority focus first on systematically identifying and addressing the barriers that are preventing effective participation in the current market. The consultation references stakeholder comments but lacks a thorough analysis of the root causes limiting uptake. By understanding and resolving these issues, the Authority can ensure that any future market developments are targeted, efficient, and avoid unnecessary complexity, while maximising the value of existing and potential demand flexibility resources.
Q14. Do you consider there are other cost-effective measures that can be implemented urgently to enable industrial demand flexibility to support reliability and efficient in the wholesale market?	Orion submits that a cost-effective measure the Authority should consider enabling is allowing existing EDB-controlled residential hot water load to participate in or respond to the wholesale market pricing signals. As outlined by the Authority previously, we are in a period of transition where full-shared retailer or aggregator control over consumer resources will take time to develop.[7] If industrial demand flexibility is considered sufficiently important to warrant new market mechanisms and policy interventions, then all already available demand flexibility resources should be considered, including the 1GW of existing EDB-controlled capacity. Orion submits that the Authority's approach appears to misunderstand New Zealand's unique demand flexibility context. Rather than comparing New Zealand to other jurisdictions that are building demand flexibility from scratch, the Authority should recognise that our challenge is slightly different – we need to optimise and appropriately compensate the massive demand flexibility capability that already exists while the market-based alternatives continue to develop. As identified by EECA, all 29 EDBs in New Zealand own and operate ripple control plant, and it's estimated that just over half of all electricity consumers have ripple control – most of which is connected to hot water systems. Ripple is efficient demand flexibility that delivers over 1GW of flexible demand response, at minimal cost, with proven reliability over decades. EECA research shows that EDBs already use ripple control for a variety of purposes, including reducing peak loads, minimising Transpower charges, emergency load shedding, alleviating network constraints, maintaining grid security, deferring capital investment, amongst other purposes. Greater consumer, and system, value could be derived by expanding EDB

Questions	Orion's response
	use cases to incorporate or consider spot price management – where this doesn't conflict with existing network and system security priorities.[22] As noted earlier, managing hot water demand has the same net effect as bringing on additional generation - generators that bring on additional generation during peak periods are paid for meeting that need. As we outlined in our executive summary, EDB demand response receives no compensation, and receives limited implicit pricing signals, despite providing the same system benefit.
Q15. Do you agree with our proposal to establish an ERS? Why/why not?	Orion submits that we generally support the proposal to establish an ERS, however it is difficult to provide agreement without further detail about the scheme's design, eligibility and how payments will be set to ensure efficiency. We agree with Vector's submission on this topic. We also note that it remains unclear how much uptake there will be, or what evidence the Authority has that this load will participate in this scheme, given the prior challenges that the Authority and Orion (see our response to Q7) have identified. There is a risk that payments could be set inefficiently, either over-incentivising participation, or failing to address the reasons for limited engagement by C&I customers in ancillary services and wholesale market products to date. We look forward to the Authority's upcoming consultation, and hope that it provides more detail on the intended scheme design, eligibility (including EDB-managed load), and clarify how the ERS will complement existing flexibility market products.
Q16. For demand flexibility providers – do you consider it likely that you could make demand flexibility capacity available for an ERS in time for Winter 2026?	No comment.
Q17. Do you agree with our proposal to investigate a standardised demand flexibility product? Why/why not?	Orion submits in support of the Authority's proposal to investigate a standardised demand flexibility product.[23]
Q18. Do you support our other proposed roadmap actions? Why/why not?	Orion submits that we have concerns with several proposed actions. **Action 3** While we support the Authority developing a new clause 2.16 notice for demand response contracted by EDBs and Transpower, we note that the Authority should broaden this requirement to include all sector Participants. This would allow the Authority to develop a comprehensive picture of the use of type 2 demand response under bilateral contracts. We note that the Authority states *"we consider type 2 demand flexibility to*

[22] EECA Ripple Control of Hot Water in New Zealand, pages 14-17.

[23] Orion has previously submitted in support of the Task Force working with industry to develop standardised flexibility service contract templates for distributors, traders and aggregators. See Orion's submission on 2A and 2BC initiatives, paragraph 6a.

Questions	Orion's response
	offer the most significant opportunities to improve incentives for industrials" but "*this assessment is based on anecdotal evidence, stakeholder views, and the limited participation by industrial demand response in DD and instantaneous reserves services*". The Authority also states that "*key buyers of flexibility services are retailers…EDBs…and the grid operator*".[24] **Action 5** Orion submits that while we generally support increased transparency, we do not support Action 5 as described. Publishing existing contract prices raises commercial sensitivity concerns, as there are potential commercial sensitivities in contracts, and prices of existing or new contracts should not be put into the open market. **Action 6** Orion submits that we do not support Action 6, pending a decision on New Zealand's Distribution System Operation. Aggregators of industrial demand must be in the Code and not inadvertently harm network or grid security. We agree with Vector, that the Authority should not introduce Code to enable third-party, non-retailer load managers until and unless it requires those parties to enter a binding Load Management Protocol with their host network companies. To do otherwise would be entirely irresponsible. The same situation would not be countenanced on the transmission grid. **Action 7** Orion submits that we do not support Action 7 as written. The Authority should allow industry co-design of flexible connection contracts, led by the ENA, before pursuing Code changes. Orion supports the development of an Authority-led working group to better understand what a flexible connection is or could be in New Zealand's context. **Action 8** Orion submits that we do not support Action 8, as it appears to reflect a misunderstanding of why non-network solutions have not been widely adopted. The Authority's proposal to "*evaluate need for enhanced regulatory requirements*" suggest that EDBs are choosing not to use demand flexibility when it is readily available. That is incorrect. Orion agrees with Unison and Centralines submission, that EDBs are already subject to clear expectations and incentives to consider non-network solutions through the DPP/CPP frameworks and ID requirements. We agree with the Authority's assessment that regulatory incentives are not the primary barrier to EDB-uptake of non-network solutions. As we have described in our responses to other questions, the barrier, in our opinion, is the limited market availability of flexible resources. For example, approximately 3.3% of households (around 67,000 homes) have

[24] Rewarding industrial demand flexibility, paragraphs 4.13 – 4.14 and 5.15.

Questions	Orion’s response
	solar panels connected to the grid, [25] compared to Australia where over 38% of homes (over 4 million households) have solar.[26] Only 7,500 New Zealand homes have batteries,[27] compared to 180,000 homes in Australia.[28] This limits the distributed energy resources available for aggregators to offer as commercial flexibility services to EDBs. Orion submits that the Authority must recognise that EDBs cannot procure flexibility that does not exist. Enhanced regulatory requirements will not create flexibility where none exists.
Q19. Do you believe there are other actions that we should consider in the roadmap? If so, please outline the actions and rationale.	Please refer to our responses to prior questions for details about other actions that should be considered in the roadmap. For assistance, we have summarised these immediate/near-term actions below: • Enable existing-EDB controlled 1GW residential hot water demand flexibility to participate in wholesale markets, either via incorporation of wholesale market signals into ripple control systems, or to be rewarded for that control by market participants via payments (type 2) or explicit pricing (type 1) for the value it offers Transpower and the wholesale market. • Address education and awareness barriers through the Authority’s statutory powers. • Support market development initiatives that build distributed energy resource capability and aggregation services at scale.
Q20. Do you support the proposed sequence and timing of actions in our proposed roadmap? Why/why not?	Orion generally supports the proposed sequence and timing of actions in the proposed roadmap, but we recommend that the Authority continue to focus on optimising existing market mechanisms before creating new mechanisms.
Q21. Is there anything else relevant to this issue that the Authority should consider? If so, please provide any relevant information to support the Authority’s consideration.	Orion submits that consideration of the upcoming Government-commissioned Electricity Market Review outcomes may be beneficial, before any decisions are finalised.

[25] Solar panel install statistics in Australia
[26] Don’t expect rooftop solar to power NZ’s future, says new Meridian boss
[27] Want to slash your power bill? Go solar
[28] Rooftop solar uptake booms in 2024 - New report sparks call for national home battery rebate