Enel X Australia Pty Ltd
Level 8, 17 Murphy Street
Thorndon, Wellington, 6011
New Zealand
T +64-4-909-7546
www.enelx.com/nz/

Electricity Authority Te Mana Hiko

Submitted by email: operationsconsult@ea.govt.nz

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To whom it may concern

RE: Potential solutions for peak electricity capacity issues: Consultation Paper

Thank you for the opportunity to provide feedback on the Electricity Authority Te Mana Hiko's (the Authority) consultation paper on potential solutions for peak electricity capacity issues.

Enel X works with commercial and industrial energy users to develop demand-side flexibility and offer it into wholesale capacity, energy and ancillary services markets worldwide, as well as to network businesses. Enel X has been offering customer load into the instantaneous reserve market in New Zealand since 2009.

This submission sets out our feedback on the mechanisms we consider would be most effective in resolving the winter peak electricity capacity issues. In summary:

- Reducing the risks associated with the peak capacity gap will inevitably involve some cost, since it requires bringing on additional capacity that is otherwise not responding to high spot prices. We note Transpower's concern that "the system needs more … flexible resources to ensure there is sufficient electricity supply capacity to meet peak winter demand."
- The quickest and lowest cost way to access additional capacity is through demand response. Experience in Australia demonstrates that, with the right incentives, demand response capacity can be mobilised quickly and effectively.
- The existing mechanisms for demand response in New Zealand are not delivering the level of demand response the system needs to meet peak electricity capacity issues. Demand bidding mechanisms like the dispatch notification and dispatchable demand frameworks are fundamentally flawed, and there is very little incentive to participate in either. Similarly, spot exposure is not a viable or attractive option for many electricity users.
- A simple, out-of-market mechanism is likely to be most effective in bringing on demand side capacity quickly. This mechanism will give the system operator control over cost through the structure of the payments and by targeting resources to the periods when additional capacity is most needed. Our experience also indicates that this mechanism is a good "entry level" form of demand response for energy users, and many go on to provide other valuable flexibility services.
- An integrated standby ancillary service should be progressed as a medium term solution. As well as providing an ongoing solution to peak capacity issues, a standby market would provide an additional revenue stream for demand response providers, increasing incentives to participate.
- The biggest "bang for buck" is in the C&I sector rather than residential, so any mechanism should be appropriately designed for these customers.

We would be pleased to discuss our submission and the potential options we raise with you directly.

Regards

Claire Richards
Head of Reliability Demand Response, ANZ
claire.richards@enel.com

<table>
<tr><th colspan="2">Questions</th><th>Comments</th></tr>
<tr><td colspan="3">Chapter 2: Winter peak capacity issues</td></tr>
<tr><td>1</td><td>Do you agree with the principle that the winter capacity margin should be based on the trade-off between the cost of the hours of reserve or energy shortfall and the cost of the peaking generation needed to mitigate it? Do you have any other suggestions on factors the Authority should consider and why?</td><td>No comment</td></tr>
<tr><td colspan="3">Chapter 3: Industry is working to better coordinate their resources</td></tr>
<tr><td>2</td><td>Do you agree with our assessment of the incentives for demand response? If not, what is your view? Are there other criteria that the Authority should consider?</td><td>Demand response capacity does not turn up on its own – the right incentives are needed to bring it to market. There are currently insufficient incentives for demand response in New Zealand.

Spot exposure through a retail contract

Exposing customers to the spot price through their retail contract is a theoretically efficient approach to encouraging demand response. However, in practice there are at least two problems with relying on spot exposure to provide efficient levels of demand response, particularly during peak periods.

First, spot exposure is not a practical option for many customers. Most business and residential customers cannot actively manage their electricity consumption every five minutes, and prefer a predictable and risk-managed approach. While there are increasing options for customers to outsource control of their energy use to manage spot exposure, this approach requires a high level of trust and is not suitable for many C&I customers who have specific energy use requirements. Further, experience in Australia suggests that many customers, particularly residential customers, are reluctant to allow external control of their resources (see discussion of ARENA RERT trial at the end of this submission). Our understanding is that not many customers are currently on spot price retail contracts, likely for these reasons.

Second, the system operator has no control or certainty that expected demand reduction will be realised. Relying on spot prices to reduce demand during peak periods is unlikely to mitigate reliability risks. To be effective in addressing peak capacity shortfalls, demand response must be visible to the system operator, able to be dispatched when required, and verifiable after the fact. There is no guarantee that high spot prices will reduce demand at peak times, as the system operator has no control over whether or when it will dispatch.</td></tr>
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		There are spot price retail offers available in New Zealand today (although we note that some, including Flick, are no longer offering this). While the exact number of customers that have taken up such an offer is unclear, what is clear is that spot exposure is not driving the level of demand flexibility the system needs. While an additional incentive may encourage more energy users to take on such a contract, there is only a subset of energy users that are willing to take on the ongoing complexity and risk of spot exposure, and who have sufficient flexibility in their energy use to benefit from it. Further, we do not believe it should be the Electricity Authority's objective to push energy users to take on that type of risk. The types of energy users that the Electricity Authority should be incentivising to provide demand response are those that do not have the capability, load profile or risk appetite for spot exposure. These customers form the majority of C&I and residential energy users in New Zealand and are the ones who need a financial incentive and a different means to deliver peak demand reductions. Dispatchable demand and dispatch notification The dispatch notification and dispatchable demand frameworks are intended to encourage loads to participate in the energy market by providing demand bids that indicate their price responsiveness. However, in Enel X's experience operating in many global markets, demand bidding mechanisms have failed to see any meaningful uptake anywhere. This is because the benefits rarely outweigh the costs, complexity and risks of participating. While some improvements have been made, fundamentally, there is very little incentive for anyone to participate in the dispatch notification and dispatchable demand frameworks, and it's not clear that there is any meaningful level of participation. Participation in the framework may also be limited by customer confidentiality concerns – that is, concerns about public visibility of the price at which an energy user (particularly a business) will provide demand response.
3	Other than financial incentives, what are the other barriers to entry for demand response participation in the wholesale market that you have identified?	It is our understanding that, under the dispatchable demand and dispatch notification schemes, only the retailer or the customer itself can participate. That is, independent aggregators who activate and manage a customer's demand flexibility have no means to access those frameworks and benefit from any incentive that it provides . In Enel X's global experience, the markets that see the greatest uptake of demand response are those that separate demand response services from retail services, and allow independent aggregators to access the sources of demand response value on behalf of their customers. Fundamentally, this is because traditional retailers, particularly those that are vertically integrated, have very little incentive to activate and encourage a customer's demand flexibility. Retail and demand response services have very different characteristics. For example, demand response requires a long-term commitment by both the service provider and the customer to install the necessary hardware and software to enable demand response. In contrast, retail contracts are typically short term. As well as preventing third parties from offering services, this poses a barrier to retailers offering demand response services due to the risk of not being able to recover their costs if the customer switches retailer. While the Authority has cited some evidence of some retailers agreeing to demand response contracts, to date these appear to be limited to a few customers with relatively large loads. These customers are likely to be more sophisticated and have more resources to investigate and understand their flexibility options.

		A significant amount of education and trust is required for customers to be comfortable with offering demand response services. Third party aggregators have a stronger incentive to support customers and provide them with the confidence to participate as it's their core business. Most retailers do not have the same level of experience in offering flexibility services, and not all retailers have the level of trust required for customers to allow their operations to be controlled or interrupted. For these reasons, we consider that the separation of retail from demand response services is crucial. That is – any mechanism designed to incentivise demand response should be accessible by both retailers and independent aggregators. Fundamentally, however, there is insufficient incentive for either aggregators, retailers or individual customers to participate in a cost avoidance framework like the dispatchable demand and dispatch notification frameworks. In our global experience, the only way that the NZ electricity market will see a meaningful level of demand response is through the creation of a new mechanism that explicitly rewards demand response for delivering a specific grid need, i.e. peak demand reductions.
Chapter 4: The Authority considers it best to focus on improved market participation for DR and BESS in the short term		
4	Do you agree that the Authority should focus its resources on identifying and lowering barriers for BESS and demand side flexibility to participate in the wholesale and ancillary services markets? If so, where do you think the Authority should focus first?	We agree that demand response and BESS are the best sources of flexibility in a wholesale market with high levels of variable renewable energy such as wind and solar. However, focusing on incremental improvements to existing mechanisms is unlikely to bring on significant additional capacity. Without more fundamental changes, the potential for wider participation by C&I customers is likely to remain untapped. Key issues that need to be resolved are facilitating third party aggregators to offer demand response services without the involvement of the retailer and providing greater incentives for demand response participation. These issues are discussed elsewhere in this submission.
Chapter 5: Options to better manage supply risk for winter 2024 and beyond		
5	Do you agree that any solutions should satisfy these principles? If not, what is your view and why? Are there other principles that the Authority should consider?	It's not clear that the proposed principles will necessarily solve the problem – that is, minimising the risk that there is insufficient capacity at peak times to meet demand. Rather, these principles are likely to limit consideration of potential solutions to minor modifications or enhancements to existing arrangements. Further, focusing on solutions that are "able to be modified or removed" may not provide the necessary certainty to enable investment in new capacity. We suggest the Authority consider the following principles: • minimise the risk that there is insufficient capacity to meet demand at peak times, subject to the costs of doing so outweighing the benefits

		• provide investment certainty to encourage new capacity to become available at the times it is needed most.
Chapter 6: Financial incentives to provide flexibility		
6	Do you agree that a standard product for financial 'super peak' hedges is required?	We agree that developing standardised shape-related hedge products to support demand response will be a useful measure to help manage uncertain revenue streams and so provide customers with greater confidence that they will be able to recover the costs of providing flexibility. However, under currently available mechanisms for offering demand response, only a small number of large, energy-savvy customers that are comfortable with being spot-exposed will be positioned to make use of these products. We consider the benefits of these products would be greater if combined with other mechanisms that could expand demand side participation.
7	What factors do you think we should consider in the design of such a product?	
Chapter 7: Considering the need for an Integrated Standby Ancillary Service (operating reserves mechanism)		
8	Do you agree with our assessment of the risk for the medium to long term?	For reasons discussed in response to questions 3 and 4, the existing mechanisms to facilitate demand response in NZ have had limited uptake, and are unlikely to see any significant further uptake. While a handful of agreements have been struck for demand response, it is not clear that the current frameworks are suitable and therefore likely to activate the vast majority of latent demand response capability in NZ. Rather, additional mechanisms are likely to be required to tap into these resources. As such, a medium to long term mechanism, such as an integrated standby ancillary service, may be necessary.
9	Do you think it would be beneficial to create a new integrated standby ancillary service? What is your view and why?	Enel X supports consideration of an integrated standby ancillary service. A market for operating reserves would provide an additional revenue stream, encouraging additional demand response resources to enter the market where existing mechanisms do not provide sufficient incentive. Having access to additional capacity during critical peak periods would help alleviate the risks of insufficient supply, and integrating the service into existing market mechanisms would ensure the various services are co-optimised and so provided at overall lowest cost. Without this mechanism, or some other mechanism to further encourage demand side participation, there is a risk that insufficient flexible demand will emerge. However, we acknowledge that integrating a standby ancillary service into the existing market mechanisms could take some time, and thus may be better considered a medium term solution. We recommend that an out-of-market mechanism be pursued in the first instance as a lower cost approach that will help resolve immediate capacity issues. As discussed further below, an out-of-market mechanism has several other benefits including simplicity, revenue certainty and so incentive for demand response providers to participate, and greater control for the system operator. Given the Authority's concern about whether the benefits of a standby ancillary service would outweigh the costs, we suggest that in developing the mechanism several "gateway" decision points be incorporated to reassess the benefits of the scheme at key points in the process. If implemented, the rule could also include a mandatory review of the mechanism after three years to determine whether the benefits have been realised, and whether the scheme is still required or improvements should be made.

10	How should the costs for a standby ancillary service be allocated?	If the Authority decides to progress consideration of a standby ancillary service we would be happy to discuss development of the framework in further detail.
11	How should the residual requirement be set? Should it be an operational setting or dynamically calculated? If it is dynamically calculated, what factors should be considered in the calculation?	
12	How should deficit (scarcity) standby residual be priced in relation to scarcity energy and scarcity reserve prices?	
Chapter 8: Interim options to manage residual security of supply risks		
13	Do you agree with our assessment of the issues associated with procuring additional resource out of market? If not, what is your view and why?	Enel X strongly supports the introduction of an out-of-market mechanism, either including generation and BESS or restricted to demand response, as an initial step to bringing more demand response in the NZ market. As noted by the Authority, there is currently a challenge coordinating sufficient capacity during winter peaks. Transpower has also raised concerns about the possibility of power cuts in Winter 2024, noting "we may be operating with reduced reserves during the coldest evening peaks with low intermittent generation, leaving the system vulnerable to changing conditions or sudden faults".[1] They note there is insufficient fast-start peaking capacity or dispatchable demand response in the short to medium term, although new resources are expected to come online over the longer term. An additional mechanism is needed to address this issue in the short to medium term until sufficient flexible capacity enters the market. Given that the current market signals are not effectively addressing the winter peak, we consider an out-of-market option would provide an additional tool that is quick to implement, to ensure demand is able to be met at critical times. Resolving the winter peak effectively in the short to medium term will inevitably involve some cost. The most cost-effective way to address the gap is by incentivising additional resources through some form of capacity program. We understand that paying for capacity to be on standby can be controversial, but it is no different to the payment structure of the current ancillary service markets. Further, it's important to remember that the financial benefits of providing demand response accrue to those who provide it – i.e. New Zealand's commercial and industrial businesses, and residential consumers. In our experience, businesses that earn revenue from providing demand response use that
14	Do you think it would be beneficial to create an out-of-market tender for emergency demand response? If not, what is your view and why?	

[1] Transpower, Winter 2024 Outlook, 31 January 2024.

		revenue to increase their competitiveness by offsetting high energy costs, and often reinvest the money into other energy management solutions for their business. Nevertheless, it's possible to design a mechanism that provides an incentive to participate while minimising the amount paid to have capacity available. For example, an out of market scheme could be designed that pays a nominal amount when the capacity is not needed, then increases the payment for those short, infrequent periods when the additional capacity really is needed. Providers will respond to that signal and want to participate. The system operator could identify the need, and run a tender process to contract with potential providers. Negotiating bilateral contracts provides a greater level of control and flexibility to establish a bespoke contract that targets the times when additional resources are most needed, and at a price that the market (and ultimately consumers) are willing to pay. Multi-year contracts increase revenue certainty for providers, increasing the likelihood of participation. Further, the fixed costs of participation can be spread over a greater timeframe, lowering the unit cost. There are two mechanisms that the Authority should consider when designing an out-of-market mechanism, outlined below. **The NEM's SN-RERT mechanism** The short notice (SN) RERT mechanism is a means by which AEMO, the system operator, can contract out-of-market resources to provide additional capacity (either generation or demand response) to help fill shortfalls in supply and deliver reliability. SN-RERT capacity providers are engaged by AEMO to sit on a panel once pricing and other terms are agreed. If AEMO forecasts a lack of reserve, it seeks to contract with the providers on that panel (usually on the same day as the forecast shortfall) to provide the agreed capacity. Once contracted, AEMO may choose to pre-activate and subsequently activate the reserves during the identified shortfall period, but is under no obligation to. In Appendix B of the paper, the Authority raises concerns about the cost of the RERT mechanism. However, it's important to understand the mechanics of this scheme, and how participants are paid. Under the SN-RERT mechanism, providers are only paid if dispatched and/or pre-activated. No ongoing capacity or availability payments are payable. AEMO's goal is to only activate and dispatch RERT resources if the total cost of doing so is below the value of lost load (or value of customer reliability). The most recent example of this is from 27 Jan 2024 in Queensland, when a period of low reserve was identified on a day with very high summer demand. AEMO entered into contracts with several RERT providers, but ultimately neither pre-activated nor dispatched these resources because grid conditions changed. Consequently, no payments were made for this capacity because it wasn't needed.[2] Nevertheless, the figures shown in the report footnoted above indicate that out-of-market reserve capacity exists and is incentivised to participate through the RERT mechanism. Most of the capacity listed in the report is demand response capacity, and this is generally the case wherever RERT is contracted.

[2] See AEMO RERT contracted report, 27 Jan 2024, available here: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2024/rert-contracted-report-for-27-jan-2024-v1.pdf?la=en

		The RERT mechanism has worked well in Australia to provide capacity during critical grid periods. While originally intended as a temporary feature of the market, in 2016 the sunset clause was removed and it was made a permanent feature, with enhancements subsequently made in 2019.[3] The RERT was considered necessary to support the transition to an increased proportion of renewable energy in the market. A trial of the role of demand response in providing short notice RERT was conducted in 2017-2020 and demonstrates how quickly additional reserves can be mobilised with the right price signals. We provide further details on this trial at the end of this table. AEMO's RERT contracted reports, published every quarter, give a sense of the amount of capacity (primarily demand response) that can be activated with the right incentive in relatively short timeframes. AEMO's recent procurement of interim reliability reserve (a form of RERT) allows for availability payments, and succeeded in bringing about 130 MW of demand response capacity in a relatively short timeframe. The RERT mechanism is generally considered to be an "entry-level" demand response program, and many energy users who provide RERT have gone on to provide other demand response services, for example frequency control and wholesale demand response. However, the challenge with the RERT is that there is uncertainty about whether and when AEMO will contract for RERT, and panel agreements generally only run for 12 months. Further, the lack of availability payments can mean future revenue opportunities are uncertain, which deters some demand response providers. These issues can be addressed using aspects of the NCESS mechanism, discussed below. **The WEM's NCESS mechanism (Western Australia)** The NCESS mechanism described below is a good example of an out of market mechanisms that strikes a good balance between the incentive to participate with costs to consumers, and could be adapted for the NZ context. This mechanism was not included in the Authority's international review – we recommend that the Authority look at this mechanism in detail. The primary means for delivering reliability in the WEM is the Reserve Capacity Mechanism (RCM). The RCM is intended to ensure there is sufficient capacity to meet peak demand roughly two years into the future. The non-co-optimised essential system services (NCESS) mechanism, can be used by AEMO to manage a range of future security and reliability issues, including peak capacity shortfalls if RCM procurement is identified as insufficient. The key characteristics of the NCESS mechanism are: • It allows for the ad hoc procurement of out-of-market (or out of RCM) capacity to help deliver future reliability needs, over multiple years.

[3] The Australian Energy Market Commission decided to make the RERT permanent due to uncertainty in the market, particularly as a result of the increase in renewable energy, and the RERT was seen as a more efficient mechanism than the available alternatives. The AEMC considered potential market distortions and costs created by RERT in reaching their decision. In 2019, enhancements were made to the RERT to recognise the increased use of the mechanism as a result of changing system needs.

		• The system operator is able to define the specific periods when shortfalls are expected to occur, giving it flexibility to target the specific periods when additional capacity is most needed. • Services are procured in bilateral contracts between AEMO and capacity providers, including demand response providers. • Providers receive an availability payment (per MW) and, if triggered, an activation payment (per MWh provided). Prices for availability and activation are negotiated upfront through a tender process, providing the system operator with control and certainty of cost. The WEM also has a shorter-term, RERT-style mechanism - the Supplementary Reserve Capacity mechanism (SRC), that it can use to plug shorter-term capacity shortfalls. Recent use of these mechanisms has demonstrably activated latent demand response capacity. In August 2023, AEMO released an SRC tender to procure additional capacity to help plug a forecast shortfall in summer 2023/24. By December 2023, AEMO had contracted with 160MW of new capacity, the vast majority of which was demand response.[4] Enel X has also recently been contracted to supply 120 MW of flexible demand capacity under the NCESS framework for 2024-26.[5] The WEM is a smaller market than the NZ electricity market. These recent WA procurements show what can be achieved, and quickly, when the right incentives are put in place to activate demand side capacity. The NCESS procurement was particularly successful in attracting multiple demand response service providers and many customers to participate because of its longer contracting period (two years), and the economic incentives involved. Availability payments provide sufficient revenue certainty to make it attractive for customers to participate. Activation payments then appropriately recompense customers for providing demand response when called, e.g. to cover the cost of lost production. **Impact on longer term price signals and future investment** We consider the impact of an out-of-market mechanism on longer term investment signals would be limited for several reasons. Out-of-market mechanisms are generally intended to bring in additional resources that would not otherwise participate in the market. This is reflected in schemes internationally that do not allow resources to participate in the out-of-market scheme if they are already participating in-market. Many customers are not suited to providing demand response via existing market mechanisms. For the reasons discussed in response to questions 2 and 3, it may not be economically or technically feasible for them to participate on an ongoing basis. However, with the right incentives, it may be possible for them to offer capacity for short periods of time with limited frequency over the course of a year.

[4] See SRC tender results, available here.
[5] See NCESS tender results, available here.

		In Enel X's experience as a demand response aggregator, persuading consumers to provide demand response can be challenging for multiple reasons, including concern about the impact on their operations. An out-of-market option that requires a lower initial commitment could help demonstrate to customers that future market participation may be possible. As such, it could have the effect of actually *increasing* market participation. Restricting participation in the mechanism to demand response would resolve the Authority's concerns about the longer term impact on investment signals for generation and storage capacity. However, our experience in international markets suggest this concern is not warranted. Generation resources already have an incentive to run as often as possible when prices are above their marginal cost, and particularly in times of scarcity when the spot price is high. Therefore generators are already incentivised to participate in the market at peak times. For similar reasons, BESS are already likely to have sufficient and greater incentives to participate in the market rather than via an out of market mechanism that may or may not be called upon. As noted above, the majority of capacity contracted under the RERT, SRC and NCESS mechanisms is demand response. **Use of the dispatchable demand mechanism** We do not consider participation should be limited to demand response that is eligible to join the dispatchable demand regime. We consider this would unnecessarily limit the potential pool of resources that are available, noting there are currently only two dispatch participants.[6] Instead, dispatch compliance can be achieved through upfront testing and penalty arrangements that are commonly used in such schemes internationally. We would be happy to discuss these types of arrangements with the Authority in more detail.
15	Do you think it would be beneficial to provide payments to resource providers for any uncleared generation and/or dispatchable demand? If not, what is your view and why?	As noted above, the limited participation in dispatchable demand to date suggests that any scheme relying on this mechanism may not effectively tap into the latent demand response capacity that may be available but not suitable to participate through the dispatchable demand mechanism. Customers who have the skills, capability and risk appetite for spot exposure, either through their retail contract or the dispatchable demand framework, are probably already doing so. However, low uptake levels of both options suggest that neither is a suitable option for the majority of energy users, even if the incentives to participate and increased. For this reason we consider a separate, out-of-market mechanism is likely to be more effective in activating demand response capacity.
16	What do you consider to be an appropriate scaling factor to determine the price for residual and why?	
17	What is your view on the factors the Authority should consider when valuing the	

[6] Dispatch-capable load station (DCLS) register on the Electricity Authority's website, accessed on 23 February 2024.

	costs associated with a standby ancillary service?	We note the Authority's concerns about interim options for addressing the winter peak effectively being "costly insurance policies that shift the risk from industry participants to consumers". However, without an additional mechanism, consumers already face significant risks and costs if there is load shedding due to insufficient capacity.
18	What other options should be considered to better manage residual supply risk for winter 2024?	
19	Do you have information on any other international standby ancillary services and their positive impacts? If yes, please share your information.	

The AEMO-ARENA SN-RERT trials

The AEMO-Australian Renewable Energy Agency (ARENA) demand response short notice RERT trial provides useful insights into how, when provided with the right price signals, significant amounts of demand response capacity can be identified and quickly brought on to provide additional capacity when it is needed. The full results of the trial are available in ARENA's Year 3 report. In summary, the key results included:[7]

- A total of 184 MW of capacity across 10 programs was contracted by Year 3 of the trial
- More demand response was delivered than contracted in each year of the trial
- For residential customers, behavioural demand response approaches were more popular than direct load control – customers were not willing to cede control of their equipment
- Automated technologies, rather than manual curtailment, delivered better outcomes for C&I customers
- Participants and their customers reported that the trial gave them useful experience and a greater interest in exploring demand response options.

Most of the demand response capacity was provided by C&I customers, and over-delivery of contracted capacity was primarily from C&I customers. These findings support our experience that C&I customers are likely to provide the bulk of the demand response capability compared to residential customers, so it is important that any scheme to deliver emergency demand response capacity be appropriately designed to provide the right signals for these customers.

[7] See ARENA, Demand Response Short Notice RERT Trail Year 3 Report, October 2021.