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Submission on **driving efficient solutions to promote consumer interests through winter 2023**

Submission to the Electricity Authority

From the Electricity Networks Association

Contents

The Electricity Networks Association (ENA) appreciates the opportunity to submit on the Electricity Authority's consultation on '**Driving efficient solutions to promote consumer interests through winter 2023'**[1].

ENA is helping deliver a low-carbon future for New Zealanders — a future based on reliable, safe and affordable electricity networks.

We represent all 27 lines companies which operate the poles and wires delivering electricity to every region across New Zealand.

Our industry:

- employs 10,000 people
- delivers energy to more than two million homes and businesses
- has spent or invested $8 billion in the last five years.

What we care about most is climate, customers and collaboration. For more information about ENA, visit our website.

1. Introductory remarks

ENA sees the paper as a positive contribution to discussion on potential solutions to managing peak loads in 2023 and beyond.

It is a perceptive and well thought out consultation on how to improve system security and reliability during short periods when there is high load and insufficient generation.

We would note that much of the paper concerns issues that don't relate to electricity distribution businesses (EDBs), and for that reason our submission focusses only on the questions that do - specifically questions 10 and 11.

[1] Electricity Authority. Driving efficient solutions to promote consumer interests through winter 2023. November 2022.

2. Summary of key points

- **ENA sees the paper as a positive contribution to discussion on potential solutions to managing peak loads in 2023 and beyond.**

- **ENA seeks greater clarity on the proposal that EDBs submit their discretionary load to the system operator through the dispatch notification product.**

- **ENA does not agree that there is poor information available on discretionary load. The amount of discretionary hot water load is not known precisely at any point in time, but can be modelled reasonably accurately.**

- **ENA disagrees that there is uncertainty over the System Operator's (SO) ability to instruct EDBs to curtail load.**

- **ENA submits that there are insufficient universal incentives for EDBs to invest and operate hot water ripple control, especially under the new transmission pricing methodology.**

- **Subject to satisfactory clarification of detail, ENA supports the ability for EDBs to offer their available discretionary load to reduce system peaks and bolster security, but only if there are clear incentives to do so.**

- **ENA supports a work programme which results in EDBs being able to offer their available discretionary load into the market for fair compensation.**

- **The above option is superior to setting an economic value on discretionary load through the market, and then relying on secondary, non-transparent bilateral arrangements between EDBs and aggregators.**

- **ENA supports work on a new ancillary service, but an integrated service might be unachievable by next winter, 2023. The EA should therefore progress a non-integrated solution with a view to its integration in coming winters.**

3. Responses to individual questions

Below is ENA's response in your preferred format:

1. Do you agree that operational coordination performance has become more challenging for the reasons indicated above? If not, what is your view and why?	Yes
Q2. Do you agree that the factors in paragraphs 4.10 to 4.63 create information challenges or misaligned incentives, and that these make it hard to achieve optimal commitment actions? If not, what is your view andwhy?	No comment
Q3. Do you agree that it is prudent to examine options to address information and incentive gaps identified above? If not, what is your viewand why?	Yes
Q4. Do you agree with the proposed evaluation criteria? If not, what isyour view and why? Are there other criteria that the Authority should consider?	Yes
Q5. What if any other options should be considered to better manage residual supply risk for Winter 2023?	No other suggestions
Q6. Do you think it would be beneficial to publish the residual offer information used by the system operator when calculating Grid Warningand Emergency Notices? If not, what is your view and why?	No comment
Q7. Do you think it would be beneficial to provide sensitivity case spot price forecasts in forward schedules, as well as central forecasts? If not, what is your view and why?	No comment
Q8. Do you agree that cross-industry work on improving the quality ofintermittent generation forecasts is unlikely to be available for Winter 2023? If not, what is your view and why?	No comment
Q9. Do you agree that the system operator should procure an external wind forecast and ask participants to review their offers if there are large discrepancies between the forecast and offers? If not, what is your view and why?	Yes
Q10. Do you agree that the availability and use of 'discretionary' demand control (such as ripple control not used for instantaneous reserves) should be clarified? If not, what is your view and why?	See section four below
Q11. Do you agree that work should be undertaken on a new integrated ancillary service for winter 2023 to help manage increased uncertainty in net demand? If not, what is your view and why?	See section five below
Q12. Do you agree that selectively increasing ancillary service cover should be considered as an interim option for Winter 2023? If not, what isyour view and why?	No comment
Q13. If increased cover from an existing ancillary service at times is pursued further as an option for Winter 2023, what are your views on whether to utilise frequency keeping or instantaneous reserve, and why?	No comment

Q14 Do you agree the option of requiring retailers to make compensation payments to customers affected by forced power cuts should not be explored for Winter 2023? If not, what is your view and why?	No comment
Q15 Do you agree that reviewing the default pricing in the Code to apply in energy and reserve shortfalls should not be explored for Winter 2023? If not, what is your view and why?	No comment
Q16 Do you agree that an hours-ahead market should not be explored for possible adoption for Winter 2023? If not, what is your view and why?	No comment
Q17 Do you agree that mechanisms that procure additional resources outside of the spot market should not be explored further for Winter 2023?If not, what is your view and why?	No comment
Q18 Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?	Yes
Q19 Do you agree that options F and G should be assessed further to determine if they are likely to have net benefits? If not, why not?	Yes
Q20 Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?	No comment
Q21 What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?	No comment

4. Response to question 10

Q10. Do you agree that the availability and use of 'discretionary' demand control (such as ripple control not used for instantaneous reserves) should be clarified? If not, what is your view and why?

This question relates to Option E: Clarify availability and use of discretionary demand control.

ENA's first comment is that option E raises many questions for EDBs that are not explained in the short summary of this option. We acknowledge that the EA, in its 'Next Steps' section, wanted to release the paper as soon as possible and that it appreciated some stakeholders might have preferred more detail.

4.1 'Poor Information'

The paper states that there is currently poor information available on the level of discretionary demand that EDBs can readily curtail if called on to do so.

This is accurate to a degree, in that forecasting the impact of shedding discretionary load, which is largely hot water load, is not an exact science. The precise amount of load that can be curtailed by ripple control at any one moment is dependent on a range of factors largely outside the control of EDBs.

The primary uncertainty is that availability of controllable hot water load varies depending on, mainly, the time of day and the concomitant link to customer behaviour at that time of day. For example, the amount of discretionary load that could be curtailed is quite different at, say, mid-morning (when many residential cylinders would not be heating and therefore load control has little effect), and evening and morning when customers are using much more hot water (and so ripple control would succeed in reducing load).

That said, individual EDBs should, based on historical patterns and system testing, be able to estimate discretionary load that could be curtailed through ripple control at any one part of the day. These loads would vary between EDBs. Those with high penetration of controlled hot water cylinders could clearly curtail more load than those EDBs with large numbers of consumers using gas, instantaneous electric, or biofuel systems to heat hot water.

Given that EDBs can estimate their discretionary load, it is unclear why the SO has difficulty collating this information and then forecasting, to a reasonable degree of accuracy, the opportunity to shed system-wide discretionary load at any one part of the day, typically during the morning and evening winter peaks.

Gathering of this information would not seem to be an onerous task. Even if difficult, collation would seem sensible and, indeed, essential for an entity which benefits from receiving as much information – generation *and* load – as possible to maintain system security. And uncertainty over hot water demand is lower than many other demand types taken into consideration by the SO's demand forecasts.

However, it's claimed that at present the SO must phone all EDBs individually to retrieve information on their forecast discretionary load. This does not seem necessary as it could be modelled and estimated based on historical information polled from EDBs. An example of ready accessibility is the near real-time data, which includes available sheddable load, gathered by the upper South Island load management group. This data is made available to the SO.

We agree that in future we could see a greater amount of controllable hot water load through smarter systems not activated by ripple signals, and that EV load could be controllable, but this added controllability is outside the scope of this consultation, which focuses on winter 2023.

- **ENA does not agree that there is poor information available on discretionary load. The amount of discretionary hot water load is not known precisely at any point in time, but can be modelled reasonably accurately**

4.2 Uncertainty over right to curtail

The paper says that there is uncertainty over the right to curtail discretionary load and under what circumstances.

ENA submits that there is minimal uncertainty; the SO has clear authority to order the curtailment of hot water load. There are two situations where the SO can direct EDBs to switch off hot water and/or disconnect customers. The first is for seasonal supply shortages and is not relevant to this consultation.

In the event of a grid emergency, the SO has powers set out in the Code[2]. Clause 6(1) (e) states that the SO can take "any other reasonable action". This is in addition to 6(1) (d) which allows it to direct EDBs to disconnect customers.

Here is the full clause 6(1) with ENA's bold highlights:

If an unsupplied demand situation, or insufficient generation and frequency keeping gives rise to a grid emergency, the system operator may, having regard to the priority below, if practicable, and regardless of whether a formal notice has been issued, do 1 or more of the following:

(a) request that a generator varies its offer and dispatch the generator in accordance with that offer, to ensure there is sufficient generation and frequency keeping:

(b) request that a purchaser or a connected asset owner reduce demand:

(c) require a grid owner to reconfigure the grid:

(d) require the electrical disconnection of demand in accordance with clause 7(20):

*(e**) take any other reasonable action to alleviate the grid emergency**.*

In addition, clause 7.21 states that "**Each connected asset owner or grid owner must act as instructed by the system operator operating in accordance with clauses 6 and 7**".

- **ENA disagrees that there is uncertainty over the SO's ability to instruct EDBs to curtail load.**

4.3 Insufficient Incentives

Notwithstanding the above two points, ENA supports a future in which EDBs can offer their customers' discretionary load to reduce peaks and bolster system stability in exchange for appropriate compensation. Given the challenges ahead, this contribution is constructive and sensible - assuming there are sufficient incentives for EDBs to, on the one hand, invest in ripple and other controllable load, and, secondly, offer price inducements to support controlled-rate tariffs.

It should be noted at the outset that EDBs have a variety of reasons for managing hot water load. For example, EDBs with a high penetration of ripple control can use it to reduce peak demand and congestion at grid-exit points or zone substations, thereby maintaining grid security and deferring

[2] Electricity Industry Participation Code 2010. Schedule 8.3, Technical Code B, p261

capital expenditure and network upgrades. For these EDBs, maintenance of reliability and reducing expenditure are clear and obvious reasons for investing in ripple control.

In addition, some EDBs turn off hot water discretionary load to help lower the price of generation at peak times, expecting that lower wholesale market spot prices will pass to consumers through retailers. Another incentive is that some EDBs offer their discretionary load into the reserves market.

However, a significant universal incentive for EDBs to invest in ripple control was removed with the withdrawal of Regional Coincident Peak Demand (RPCD). As a result of the end of RCPD, some EDBs are reducing their hot water load control, narrowing the gap between their controlled and uncontrolled tariffs, and questioning the merit of investing in their ripple control equipment.

While there are a range of incentives to activate hot water control, some ENA members are questioning whether these are sufficient to invest in and activate their ripple control. However, the paper suggests that there could be a new universal incentive in future.

The ability to offer discretionary load into the wholesale market in return for payment would be a major component of the much-anticipated 'flexibility services' market, which is a sensible way of reducing peak loads to curb expensive investment in network or generation infrastructure.

ENA is therefore supportive of a work programme which leads to its members being able to offer their available[3] discretionary load into the market clearance system – potentially though a dispatch notification into the new real-time pricing regime. It is desirable though unlikely that this could be achieved by the 2023 winter.

- **EDBs use hot water load control for a variety of reasons, including their customers' grid security and deferment of capital spending and upgrades.**
- **The withdrawal of RCPD removed a significant universal inventive for EDBs to invest and operate hot water ripple control.**

[3] EDBs which are already load controlling for their own grid security or capital deferment reasons, can offer only their remaining discretionary load, if any.

- **Subject to satisfactory clarification of detail, ENA supports the ability for EDBs to offer their available discretionary load to reduce system peaks and bolster security, but only if there are clear incentives to do so.**

4.4 Distributors best placed to manage load

The EA discussion paper says that "Ideally, distributors would be incentivised to offer demand management contracts to retailers to manage their customer load on their behalf."[4]

ENA's strongly believes that distributors are currently best placed to manage ripple control, especially as we transition, and before flexibility markets are firmly established.

EDBs have the knowledge and understanding to manage discretionary load, and load management is critical for network purposes. This importance is reflected in schedule eight of the Default Distributor Agreement, which states that grid security is the number one priority for controlling load, ahead of any other right to control load[5].

4.5 Dispatch Notification Product

Turning to EDBs using the Dispatch Notification Product (DNP), it is unclear how this would operate. Before supporting, ENA would like to know more detail including:

1. Would EDBs be compelled to submit a DNP, or would it be voluntary?
2. How often would a DNP submission be required? Daily? Weekly? At times of clear risk? Only after issuance of a formal notice (e.g. Low Residual Customer Advice Notice, or Warning Notice?)
3. What would happen if EDBs over-estimated their ability to shed discretionary load and could not deliver this load reduction?

If the answers to these questions are respectively: voluntary; occasionally; and there were no consequences, ENA would support the use of DNPs to inform the SO about potential discretionary load. ENA's backing is contingent on the ability of this load to eventually be monetised to support investment in ripple control and other load management technologies.

- **ENA seeks greater clarity on the proposal that EDBs submit their discretionary load to the system operator through the dispatch notification product.**

[4] Ibid, p25

[5] Default Distributor Agreement Template. June 2020, p 76.

- **ENA supports a work programme which results in EDBs being able to offer their discretionary load into the market for fair compensation.**

4.6 Exchange in value

As stated above, EDBs require universal incentives to continue to maintain and operate their ripple control. Indeed, the paper refers to incentives, stating accurately that these are “not clear”.

It is important that there are clear universal incentives (as opposed to regional incentives based on penetration of ripple control and its ability to maintain grid security and defer capital spending).

These incentives will help make a business case for investing and maintaining hot water load and other discretionary load for the benefit of consumers. They are important in the context of the value, or savings, which can be generated by hot water control. A 2020 report on ripple control estimated that more than 1.1 million consumers had a total of 987 MW of network load connected to ripple control.[6]

Ripple control should not be seen as costless. The EECA report said ripple control costs $10 per ICP per year, assuming a 30-year life of a ripple relay. The total annual cost of providing ripple control ranges between $10 and $27 per kW of controllable load, and between $10 and $19 per ICP. Absent RCPD, there is little direct financial incentive for EDBs to activate ripple control. As such, EDBs wanting to contribute ripple control need clear incentives to maintaining this capability.

4.7 Current Consultation

The current consultation raises the possibility of an exchange in value at some time in future, but this appears to be ‘off market’ - EDBs offering their discretionary load through direct contracts with retailers or other market participants. While this possibility cannot be excluded, ENA sees a simpler and easier option is for EDBs to offer their discretionary load into the market at a price per megawatt. While this is a demand side transaction, in the context of system stability these offers would be no different to offers from generators and grid-scale battery owners, or offers into the reserves market.

In the short term (2023), there appear to be little opportunity for an exchange in value. This is at odds with the 2021 Hodgson report[7], which stated “The market requires much greater demand side

[6] Energy Efficiency and Conservation Authority. Ripple control of hot water in New Zealand. September 2020.

[7] Ministry of Business, Innovation and Employment. Investigation into electricity supply interruptions of 9 August 2021. Published November 2021.

participation. This will be essential if goals of greater electrification and decarbonisation are to be achieved.”

Hodgson et al said that ripple hot water control and replacement technologies are envisaged as “being at the heart of a transition to a richer demand side participation in the market over the next decade”.

4.8 Offer price of no benefit to EDBs

The paper says that EDB notification of discretionary load would, in addition to providing greater visibility, assist participants with short-term-contracting and commitment decisions. This would suggest that EDBs discretionary load notification would be linked to a price of, say, $2,500 per megawatt.

This price would help generators make decisions on their bids, as they would conclude there were minimal incentives to offer bids over $2,500 as, at that price level, load would fall due to hot water control.

While this price signal is a significant financial benefit to retailers and other purchasers, who will avoid expensive electricity prices at peak times, and will also benefit generators in guiding their bids, it will return no direct value to EDBs.[8] So, essentially, all the benefits of dispatch notification of available ripple control would flow to generators and retailers, and none to EDBs.

This is why ENA instead supports a regime in which EDBs could bid available discretionary load and price into the market. A fair exchange in value would create incentives for EDBs to bid their discretionary load and continue to support, and enhance, their ripple control regime.

At present there is no monetary value in providing interruptible load into the market. It’s more about avoidance of cost. It could be argued that setting an economic cost on interruptible load might support off-market contracts (e.g through EnerNOC[9]) between EDBs and retailers or others exposed to the spot market. But the linkage between these variables is uncertain. And the EnerNOC offering is at present between major users who can curtail load, pooled and offered into the reserves market.

[8] Some might say there is an incentive to community-owned EDBs, in that lower spot prices reduce the costs of retailers, and therefore reduce the bills of consumers in an EDBs geographic area, but this link is opaque.

[9] EnerNOC is a Rome-based global provider of demand response applications and services

While EDBs see off-market contracts as a viable option, it is desirable that there is also the ability to offer discretionary load through the established market clearance system.

- **ENA supports a work programme which results in EDBs being able to offer their available discretionary load into the market for fair compensation. This option is superior to setting an economic value on discretionary load through the market, and then relying on secondary, non-transparent bilateral arrangements between EDBs and aggregators.**

5. Response to question 11

Question 11: Do you agree that work should be undertaken on a new integrated ancillary service for winter 2023 to help manage increased uncertainty in net demand? If not, what is your view and why?

ENA agrees that it would be beneficial for work to be undertaken on a new ancillary service for the winter of 2023. Ideally, the service would be integrated into the rest of the spot market. Practically, an integrated service might not be implementable within the short time window before June next year, as it will likely require adjustments to software, the Code, and other settings.

It is noted that the Authority is wary of any non-integrated service because it might 'rob Peter to pay Paul', with providers potentially exiting the reserves market for a more lucrative arrangement.

But given the importance of finding urgent solutions, the Authority might consider an ancillary service that is not integrated into the market in 2023, with the knowledge that it would be integrated in subsequent winters. It would be better to have an ancillary service that helps keep the lights on for consumers, the most important goal for the industry, than absent that option.

Coincidentally, the Authority would be aware that there is an ancillary service under development by market participants, including four ENA members.

This product gives a degree of surety to generators, battery owners, and demand response providers that they can participate in the market for a small number of hours (e.g. one to four). This surety would be helpful in particular to generation which is expensive to start, warm up, and operate, encouraging them to prepare their kit for supplying peak periods.

In summary, ENA supports work being undertaken on a new ancillary service for winter 2023. While the intent is that the service will ultimately be integrated into the spot market, this might not be achievable by 2023. Keeping the lights on should be put first, before any potential negative implications for wholesale market pricing.

- **ENA supports work on a new ancillary service, but an integrated service might be unachievable by 2023. The EA should therefore progress a non-integrated solution with a view to its integration in subsequent winters.**

6. Concluding remarks

ENA welcomes the opportunity to submit on your constructive and well-written paper and would welcome follow-up questions.

7. Appendix A

The Electricity Networks Association makes this submission along with the support of its members listed below:

Alpine Energy

Aurora Energy

Buller Electricity

Centralines

Counties Energy

Eastland Network

Electra

EA Networks

Horizon Energy Distribution

Mainpower NZ

Marlborough Lines

Nelson Electricity

Network Tasman

Network Waitaki

Northpower

Orion New Zealand

Powerco

PowerNet

Scanpower

The Lines Company

Top Energy

Unison Networks

Vector

Waipa Networks

WEL Networks

Wellington Electricity Lines

Westpower.