1 October 2024

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By email: policyconsult@ea.govt.nz

Dear Grant,

Submission to the Electricity Authority (Authority) on Code review programme number six: September 2024

Electricity Networks Aotearoa (ENA) appreciates the opportunity to make a submission to the Authority on its consultation paper on *"Code review programme number 6".*

ENA is the industry membership body that represents the 29 electricity distribution businesses (EDBs) that take power from the national grid and deliver it to homes and businesses (refer Appendix A for list of members). EDBs employ 10,000 people, deliver energy to more than two million homes and businesses and have spent or invested $8 billion in the last five years. ENA harnesses members' collective expertise to promote safe, reliable and affordable power for our members' customers.

In the opening remarks, the Authority refers to the changes in the consultation as "relatively small amendments". Whilst we accept that most of the proposed changes meet this definition, we are concerned that the Authority is understating the significance of proposal CRP6-002 regarding sharing control of load.

We have therefore focused the bulk of our submission around this one proposed change, with a brief section at the end to address our views on certain of the other proposed changes in the code review programme.

1.1 CRP6-002 Sharing control of load between distributors and others

ENA supports the ongoing development of new customer propositions for managing consumer devices' load and injection, and the increasing choice and efficiency these should unlock. New technology provides the ability for individual consumers' devices to be managed in different ways, by different parties, enabling a much wider range of preferences to be met more effectively.

Ultimately, within the bounds of the supply arrangements that a consumer has secured, the consumer should be free to choose how they participate in load management schemes. We believe consumers want to get the most value out of their controllable load, for the least effort and inconvenience.

However, how the future system will operate considering these new propositions and services is complex and different from how it has operated in recent times. New roles played by, and interfaces between, industry participants are evolving rapidly and remain unclear.

The Authority has highlighted this evolution very recently in its workstream on Future System Operation and its development of draft guidance for distributor involvement in the flexibility services market. ENA, through the Future Networks Forum, has been exploring the future capability, roles and functions required to enable distributed flexibility resources to play their full roles in minimising whole-system costs to consumers. This work will include exploring and developing the new interfaces and load management protocols required between participants.

Considering this context, and the lack of clarity in certain aspects of the future system, it is reasonable for the Authority to address what it knows now as clear and obvious shortcomings in the Code.

1.1.1 Dual control is complex

However, even with this motivation, the changes required to enable dual control of distributed resources are far more complex than the Authority has considered in this proposal. Addressing these changes must be done in a considered, systematic way, rather than through a series of ad hoc, bespoke Code changes that could result in unintended consequences for the consumer and/or the network.

For example, the load management components of the DDA appear framed around the traditional management of hot water load via ripple systems, using terms such as 'Load Control Equipment' and 'Load Signalling Equipment', albeit the definitions state *"may include but is not limited to ripple receivers and relays"*. Where multiple parties are controlling under clause 5.3, both parties may be using different types of systems to manage load and/or send signals, which also needs to be considered as part of these definitions.

Load management services are evolving rapidly from the current construct, and now include injection from consumers' resources. Examples include remote management of EV charging over the internet, directly via contact with the EV itself, rather than through external controlling equipment installed in the consumer's home. In NZ and overseas, EDBs are also implementing 'flexible connections', which, rather than including direct management of load behind the meter, manage access to the network of a whole house or business. These examples do not appear to fit neatly within the existing DDA construct. Nor does it appear that clauses 5.7 and 5.8 have considered how dual- or multi-party control under clause 5.3 would obligate parties to protect each other's systems.

1.1.2 The proposed change should be considered as part of a wider programme of Code development relating to enabling flexibility of resources

In light of this rapidly evolving context, we were surprised to see these proposed changes included in an omnibus, and described as "relatively small amendments", as opposed to being part of a wider programme of Code development relating to enabling flexibility resources. There also is no reference to the developments in those other Authority workstreams, the most prescient of which is the draft guidance on distributor involvement in the flexibility services market.

Several of our members are engaging with, and hosting, retailers piloting new customer propositions including management of hot-water and EV charging load. These pilots are leading to learnings and increased understanding on both sides. This experience has unearthed other areas of misunderstanding or misalignment between the DDA's language versus likely intent. Although the trials are small-scale at this stage, there are instances of negative customer experience and are already indicating the 'herding' risk to network security that we have long been indicating to the Authority. It is concerning that the Authority is rushing to enable dual control without equal/due consideration of the potential risks this poses to network stability. If the Authority is to undertake a round of changes at this point, in lieu of a more fulsome review of market arrangements for load and injection management, then we suggest further critical changes must be made concurrently.

Some of these changes are detailed in our response to Question 5 below. We would appreciate the Authority engaging with each suggestion in turn and would be happy to engage further with Authority staff.

For decades, distributors have been responsible for ensuring consumers' service levels in relation to their manageable loads are met or exceeded. These service levels are signalled via the registry. Such control is fundamentally intertwined with how EDBs manage and safely operate their networks. In the event a retailer also acquires the right to manage the same load, under clause 5.2, it is not clear at this point:

a) How this is signalled to the rest of the sector, via the registry or otherwise; and
b) Which party has the ultimate responsibility for ensuring the consumer's needs and preferences are met.

We assume that b) is intended to be agreed under the Load Management Protocol, but a) is unclear at this point.

1.1.3 Addressing the Authority's specific questions

Question 1 – Do you agree the issue(s) identified by the Authority need attention? Any comments?

Framing of the problem requires consideration of how the DDA is drafted

The Authority makes several statements in the framing text for Proposal 2 that are inconsistent with how the DDA is drafted.

For example:

FRAMING STATEMENT	ENA COMMENT
"Clauses 5.1 and 5.2 specify that each party may control a customer's load where the customer has agreed (or elected to take the controlled service)."	This is not entirely true. While we agree that the ability for a consumer to opt in and out of control services is critical to broader development and uptake of flexibility services, Clause 5.1 (a), which covers most distributors' controlled tariffs, explicitly does <u>not</u> include a requirement that the customer agrees or elects to have their load managed by the distributor. Given the lack of a direct relationship between distributors and end consumers, and the fact that distributors bill retailers rather than end consumers, this is entirely appropriate. The operative agreement in 5.1 (a) is, in fact, between the retailer and the distributor. Under 5.1 (a), the distributor must offer a controlled tariff <u>and</u> charge the retailer that controlled tariff for that ICP. The customer does not necessarily need to be on a retail

FRAMING STATEMENT	ENA COMMENT
	proposition that includes control, nor need to have specifically elected to be on any controlled tariff option, although we expect this to be the norm. In contrast, offers by the distributor or retailer under clauses 5.1(b) and 5.2 respectively <u>do</u> require the customer at the ICP to consent to their load being managed.
"Much of the hot water load is currently controlled by the distributor as the incumbent, using a controlled load price option, giving the consumer some benefit for allowing the distributor to control the load. This load is also used by the distributor for grid emergencies."	The Authority appears to have overlooked the fact that a key use of load control by the distributor is to manage <u>network</u> emergency events, such as response to storms or other extreme events and unplanned network outages. These are very different to grid emergencies and can be as localised as a car-versus-pole incident. We explore the impact of this oversight in our specific comments on the drafting below and suggest ways to clarify the use of load control for network emergency events.
"…there is a risk consumers will opt out of the distributor's controlled load price option to take up the higher benefit from a trader/retailer's service. This means the load could be lost to the distributor during a grid emergency and could put the power system at risk if a material number of consumers opt out."	As noted above, the consumer does not necessarily need to **opt into** a distributor's controlled tariff under 5.1(a)— the operative requirement is that the distributor bills the retailer for the 5.1(a) option at that ICP. As noted above, this is appropriate given the distributor lacks a direct relationship with the end consumer and bills the retailer rather than the end consumer. Therefore, under clause 8.4, the retailer is in a position to elect to have the ICP removed from the distributor's control tariff, and it appears they can do so with or without the consumer's involvement or consent. Further, if ICPs are taken off an EDB's controlled tariff by the retailer (under clause 8.4), our members are concerned that the inability of the ripple system to discriminate between houses that are on the tariff and those that are not may inadvertently lead to EDBs controlling some load that they are not entitled to. How these changes are effected physically, including whose responsibility it is to remove the ripple relay for example, is unclear at this point. Critically, and more importantly, in framing the problem this way, the Authority has overlooked the fact that if the retailer is managing load under a 5.2 option, the load **is still required** to be available to manage a grid emergency <u>and a network emergency.</u> This is set out clearly under clauses 5.3 and 5.6 (iv), and Schedules 4 and 8. In short, the distributor does <u>not</u> lose the ability to instruct the load to be managed in a system emergency event (grid or network) just because the retailer has secured access via 5.2, even if the ICP is

FRAMING STATEMENT	ENA COMMENT
	taken off the distributor's controlled tariff. However, the distributor must now orchestrate the load via the retailer, rather than directly using its own system, to ensure there is robust coordination of load to manage overall system security. This is one of the key reasons 5.6, Schedule 4, S8.1 and S8.2 are included in the DDA and why the load management protocol (LMP) – and adherence to it by retailers – is so important. However, as noted below, there is unnecessary confusion in the industry about whether the retailer is obligated to use its load management at the distributor's request to help manage <u>network</u> emergency events, or to avoid them occurring in the first place. This would appear to be the clear intent of the drafting at clause 5.6 and in the definition of System Emergency Event. We have suggested some simple additions below that would help clarify.

Question 5 – Do you have any comments on the drafting of the proposed amendment?

Proposed changes are incomplete – further critical clarifications are required

While the proposed amendments do appear on the surface to address the issue of dual control, the Authority needs a clear opportunity to make further important clarifications that would significantly improve the chances of coherent and effective load management protocols being agreed upon.

Our members' experience to date in discussing load management protocols with retailers has revealed some fundamental differences in interpretation, which need to be addressed urgently.

We recommend these further changes below.

CODE AMENDMENT	ENA COMMENT
Scope The DDA governs the relationship between a distributor and a retailer. There is **no parallel relationship** or agreement binding a distributor and any non-retailing entity (e.g. a load aggregator, or virtual power plant operator) that might be managing load on the distributor's network –	The lack of an equivalent to the DDA, and especially Clause 5 (and Clause 5.6), for non-retailing entities managing load, is a significant gap in the Code. There is no parallel requirement ensuring that such entities operate their load under Good Electricity Industry Practice, are required to notify and communicate with their host distributor, are required to understand the operating limits of the network they are operating on, or to coordinate their activity with the host distributor, including in system emergencies. These parties may already be operating manageable devices on distributors' networks without the distributors having any knowledge. A parallel situation occurring on the transmission network – a party connecting to and operating on the transmission network without

CODE AMENDMENT	ENA COMMENT
even if they are participating in the national wholesale markets.	the knowledge of either the Grid Owner or System Operator – would be viewed as completely outrageous. This omnibus consultation is not the appropriate vehicle to remedy this. However, for completeness, we are registering our concern that the Authority is knowingly and wilfully allowing this situation to continue, despite repeated submissions from parties highlighting this gap and the risk it creates. At best, it creates an unlevel competitive playing field between retailers and non-retailers, as non-retailers are not bound by the Code or DDA. At worst it creates unmanageable and unacceptable risks to network, consumer and public safety that the host distributor is not even aware they need to manage.
33.2 Definitions The Authority must clarify that network emergencies are different from and only sometimes coincide with grid emergencies. Ideally, network emergency events would be defined in 33.2. A System Emergency Event (SEE) can then be defined simply as 'either a grid emergency or a network emergency'. This definition could be a clarification of what is already in the DDA, as set out in this row, or a more fit-for-purpose definition, as set out in the row below.	The Authority does not propose to modify the definition of SEE in Clause 33 of the DDA, but it should do so. Currently, the definition of a SEE in 33.2 states: "***'System Emergency Event'*** *means a grid emergency in accordance with the definition of that term in Part 1 of the Code and, in respect of the Network, any emergency situation in which:* *(a) public safety is at risk;* *(b) there is a risk of significant damage to any part of the Network;* *(c) the Distributor is unable to maintain Network voltage levels within statutory requirements; or* *(d) an Unplanned Service Interruption affecting part or all of the Network is imminent or has occurred."* The sector needs more clarity on the fact that a SEE is not simply synonymous with a grid emergency. The prioritisation set out in S8.1 mistakenly refers to a grid emergency rather than SEE and is clearly inconsistent with clause 5.6 which refers to SEE emergencies and with Schedule 4 (Distributor's System Emergency Event Policy). As set out in the definition, it appears clear that a SEE is certainly intended to include more localised *network* emergency events that give rise to one or more of (a) to (d) above but are far below the threshold of a grid emergency. A very wide range of events may lead to a situation in which one or more of (a) to (d) may apply. In particular, (d) above clearly may apply to a very localised issue caused by (for example) a car-versus-pole incident. It also <u>explicitly</u> covers events that have not yet occurred but are "*imminent.*" This could include managing networks pre-event, for example, preparing for the onset of a storm or managing an area where the network is

CODE AMENDMENT	ENA COMMENT
	at risk of becoming overloaded due to a temporary network reconfiguration. Retailers attempting to dispatch too much load 'on' in response to a fall in energy spot prices could pose a risk to public safety and network equipment. The Authority must consider how best to give the industry the clarity required. The simplest option would be to replace 'and' with 'or', and insert 'either': "'***System Emergency Event'*** *means either a grid emergency in accordance with the definition of that term in Part 1 of the Code ~~and~~ or, in respect of the Network, any emergency situation in which: …"* This would make it clear that the network emergency does not have to coincide with a grid emergency to meet the threshold of a system emergency event. A preferable alternative would be to create a new defined term in 33.2 – **Network Emergency Event** – which includes the remainder of the definition of a SEE that is not a grid emergency, with corresponding changes made to Schedules 4 and 8: **NEE alternative 1** '***Network Emergency Event'*** *means in respect of the Network, any emergency situation in which:* *(a) public safety is at risk;* *(b) there is a risk of significant damage to any part of the Network;* *(c) the Distributor is unable to maintain Network voltage levels within statutory requirements; or* *(d) an Unplanned Service Interruption affecting part or all of the Network is imminent or has occurred."* The definition of a SEE could then be: "'***System Emergency Event'*** *means either a grid emergency in accordance with the definition of that term in Part 1 of the Code ~~and~~ or a* ***Network Emergency Event****".* This overt inclusion of network emergency events in the definition of SEE is critical. It has a significant bearing on not just the contents of the protocols agreed upon under 5.6 but also the likelihood of compliance with the LMP, both by retailers and non-retailer aggregators – to whom the LMP must be extended as soon as possible. As 5.6 (b) (iv) notes, a key aspect of the protocol is to ensure the retailer's load management capability "*assists the Distributor to*

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	manage Network system security during a System Emergency Event", which clearly is not required in grid emergencies alone. Further, as per 5.6 (c), during a System Emergency Event, the retailer must "*operate its controllable load in accordance with the protocol.*" The industry needs to be clear that the DDA contemplates and covers actions required in more situations than just grid emergencies. The reference in S8.1 solely to grid emergencies and not system emergencies (which include network emergencies) is unhelpful and confusing and must be corrected. This may require a subsequent round of consultation, but, in our view, is both essential and urgent.
33.2 Definitions The Authority must clarify that network emergencies are not the same as and not always coincident with grid emergencies. This could be achieved via a relatively simple clarification, as per the row above (NEE alternative 1), or adding a more fit-for-purpose definition, as set out in this row (NEE alternative 2).	As above, a SEE should be defined as either a grid emergency or a network emergency event. Rather than simply re-cutting the existing definitions, a more fit-for-purpose definition for a network emergency event would be: **NEE alternative 2** *"'**Network Emergency Event'** excludes a Grid Emergency and means a situation where, in the opinion of the Distributor, one or more of the following events has occurred, or expected to occur, in respect of the Network and urgent action is required to assist in avoiding or alleviating the situation:* *a) public safety is at risk;* *b) there is a risk of significant damage to any assets that form part of or are connected to the Network;* *c) the Distributor is unable to maintain voltage levels on any part of the Network within statutory requirements;* *d) a Trader or another participant on any part of the Network has been unable to maintain operation of one or more controllable resources within the Operating Limits provided by the Distributor; and/or* e) *an unplanned interruption to electricity supply to one or more ICPs on the Network is imminent or has occurred."* This clarifies the forward-looking aspect of a network emergency and the importance of the Distributor being able to issue instructions and operating limits to retailers to *avoid* emergencies occurring or being exacerbated. These powers would mimic those the System Operator has to prevent grid emergencies, and to address them promptly should they eventuate.

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	The term 'Operating Limits' would also need definition; we envisage these would include components like ramp rates and operating envelopes.
5.1 – a new preamble is required to ensure there is no confusion that clause 5 applies to <u>all</u> management of <u>all</u> devices – potentially including injection too.	Some retailers require clarification that clause 5 and Schedules 4 and 8 apply not just to hot-water load management but to <u>all forms</u> of load and devices a distributor or trader may manage. Some retailers have also considered that managing hot-water load using a 'calendar' function – i.e. exercising the same periods of control every day in a set-or-forget way – does not qualify as 'load management' under the DDA or require a load management protocol. We believe this is incorrect. To clear up this confusion, there should be a preamble to clause 5, in a new 5.1, which states, to avoid any doubt, that: *"Clause 5 and subsequent Schedules 4 and 8 apply to all forms of load management that may be undertaken by the distributor and/or the trader, irrespective of the device(s) being managed, the controlling equipment, or the mode(s) of operation (static or dynamic)."* A definition of "Load" in 33.2 could also pose a solution to clearing up this confusion/misinterpretation. Further, at this stage, there is no reason why clause 5 and the LMP enabled by clause 5.6 should not overtly also encompass managed **injection**, for example, by home battery systems or vehicle-to-grid chargers. Injection will need to be coordinated with the host distributor in much the same way as load management for the same reasons. The Authority must make clear its position in this regard.
5.3 – imposes new obligations on distributors unnecessarily	The amended 5.3 (a) states, "… *The entrant may only control the part of the Customer's load that the Customer has agreed the Entrant may control under an agreement with the Entrant.*" It appears the Authority has only contemplated the scenario where the distributor is the incumbent and the trader is the entrant. In a scenario in which the roles were reversed, the distributor may be trying to acquire the right to manage load under 5.1 (a) or (b), which the trader currently manages under 5.2. Requiring the customer at the ICP to provide consent in that scenario raises a hurdle that, as discussed above, for good reason does not currently exist under 5.1 (a). The distributor typically has no retail relationship

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	with the customer through which to acquire that consent, and its tariff is billed to the retailer, not the end consumer. In this scenario, the distributor's acquisition of access rights under 5.1 (a), as the entrant, by billing the retailer its control tariff for that ICP, should endure.
5.4 and 5.5	The proposed changes are reasonable.
5.6 – attention needs to be paid to how equivalent protocols will be managed	The proposed additions are mostly reasonable. The Authority should consider how it will ensure the conditions in 5.6 (b) (iv) —equivalent terms— are met, how compliance is monitored, and how disputes are resolved. Presumably the protocols with non-retailing entities will also need to be equivalent. ENA recommends that EDBs publish operating protocol templates that will not require renegotiation for every new load-managing retailer. The EA should also consider how the protocol should consider the situation when two traders acquire the right to manage the same load, with or without the distributor also having that right, or the situation in which a third party that is neither a retailer nor the distributor also acquires control rights.
5.6 (b) (iv), 5.6 (c) and (d) Trader load management practices should also ensure that network emergencies are <u>avoided</u> wherever possible	The Authority should clarify that these requirements include supporting distributors in <u>**avoiding**</u> Network Emergency Events by retailers not operating controllable loads in ways that could <u>create</u> one in the first place. This would include, for example, ensuring retailers do not turn on so much manageable load at the same time, or inject from so many batteries, that the distributor is unable to maintain voltage levels within statutory requirements or that thermal limits risk being violated and equipment damaged. Such activity could also create risks to public safety. Our members understand that restoration of load after a control event is a complex matter of coordination, taking some time to achieve safely. Retailers have not had (or needed) this awareness, to date. While not acting in a way that creates a network emergency may appear obvious, retailers need a shared understanding of the importance of, and the requirement to, ensure load management

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	operates within the confines of the network's operating limits – both physical (thermal) and power quality. Existing Code requires this of distributed generation (for example in Clause 13.9A), but there is little to no precedent for manageable load. Operating in accordance with "good electricity industry practice" means different things to different parties. However, ensuring retailers' load management practices do not create network emergencies would appear to be a **clear minimum standard**. The Authority must ensure this is guaranteed before allowing parties other than distributors to acquire the rights to manage material quantities of load on distribution networks.
Schedule 8 – S8.1 The hierarchy explicitly omits network emergency events. Instead, S8.1 must refer to System Emergency Event, rather than Grid Emergency, to ensure that managing network emergencies is understood to be a higher priority than market participation.	Rather than referring to a Grid Emergency, this schedule must explicitly state that the highest priority is always to manage or avoid a **System Emergency Event**. The definition of System Emergency Event in 33.2 —referred to above— itself is explicitly clear that it includes localised network emergencies that are not Grid Emergencies. **This change is critical to ensuring new load management services are rolled out safely and securely.** This change will ensure S8.1 is consistent with the other parts of the DDA, namely 5.6 (b) (iv), the definition of System Emergency Event in 33.2 and the reference in 5.6(b), which requires the LMP to be consistent with the distributor's policy for managing SEEs in Schedule 4. By naming a grid emergency in S8.1 alone, without mentioning network emergencies, the Authority has implicitly and inadvertently reinforced a view held by some in the sector that network emergencies are a lower priority than market participation— or, more concerningly, are not a priority at all. This creates unnecessary inconsistency with Schedule 4 or Clause 5.3. Further, as noted above, retailers must clearly acknowledge that avoiding network emergency events in the first instance is a higher priority than (or a necessary precondition for) market participation. Taken by itself, Schedule 8 certainly does not give that impression. If, instead, the Authority were to insert a newly defined term in 33.2 – Network Emergency Event – as discussed above, this could also be inserted into S8.1 below or equivalent to (a) Grid Emergencies, and above (b) Market participation. This may be the cleanest way to effect this change: *S8.1 A party may use a Load Control System for 1 or more of the following purposes, which are ranked in order of priority,*

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	provided that it has obtained the right to control the load in accordance with clause 5.1 or 5.2: *(a) Responding to or avoiding a Grid Emergency: As defined in Part 1 of the Electricity Industry Participation Code 2010;* *(b) Responding to or avoiding a Network Emergency Event* *(b) Market participation: Any other right to control load.* It would be preferable to reinforce that avoiding these emergency events – not just responding to them as they arise – is also a higher priority than market participation. It is also unclear to our members how distributors' load management to defer network investment sits in this hierarchy. The Authority must make clear whether it considers this a form of "Market participation", or whether it is a different kind of load management that sits above market participation. It is also unclear whether optimisation for distribution markets (or other local flexibility markets) should sit at the same or a higher level to national wholesale market participation. As noted above, if a material proportion of load management relied on by a distributor to defer investment suddenly becomes unavailable to them, it could rapidly lead to network emergency events occurring on a regular basis.
5.6, 33.2, Schedule 4, Schedule 8 In several places, the DDA refers to 'controllable load', which is now a defined term in the Code – albeit one just '*for the purposes of Part 8*'. This has the potential to lead to confusion in the industry, and must be clarified.	Within the same omnibus, the Authority is consulting on a change to the subparagraph numbering of the definition of 'controllable load' in Part 1 of the Code. This definition applies only 'for the purposes of Part 8'. The juxtaposition of this proposal with the DDA amendments has highlighted that the term 'controllable load' means one thing in Part 8, but something different in the DDA. Our members are concerned that, where a distributor is offering hot-water load into the reserves market as interruptible load, the definition for use in Part 8 could be read as saying that this load is not available to other parties to manage. Our assumption at this point is that, under S8.1, participation in the reserves market is viewed as 'Market participation', rather than supporting resolution of a SEE. The Authority could usefully clarify this. The Authority should either clarify that the defined term for Part 8 is not in use in the DDA, or consider using a term other than 'controllable load' in the DDA.

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In summary, load sharing is complex and as a minimum, we recommend the following amendments be implemented as a matter of urgency, as misunderstandings are fundamentally affecting effective operation of dual control. We consider these are also just clarifications and are not intended to change any meanings:

- Make it clear, either directly in the DDA preamble or within the consultation's decision paper, that the load sharing being referred to is not limited to hot water control, but all types of load control.
- Make it clear that system emergency events cover both grid and network emergency events, which may not occur concurrently (suggest replacing 'and' with 'or' in the definitions in 33.2).
- Make it clear that the hierarchy discussed in schedule 8.1 covers system emergencies and not just grid emergencies.

Should any of the proposed changes above need to be clarified, or should the Authority disagree with any of them, a deeper conversation with ENA members is essential. Our members are at the coalface of attempting to enable and facilitate new load management by retailers and are acutely aware of the limitations of the DDA in this respect.

Other proposed changes in Code Review 6

ENA supports the following additional proposals made by the Authority in the Code Review 6 programme.

CODE AMENDMENT	ENA COMMENT
CRP6-003 Adding embedded generation to the definition of ICP	ENA supports the intent of this proposed change, because it provides improved clarity.
CRP6-005 Distributor interconnection point audit requirements	ENA supports the intent of this proposed change, because it reduces regulatory burden on some EDBs.
CRP6-006 Definitive obligation to pay auditors	ENA supports the intent of this proposed change, because it provides clarity and enforceability. That said, we feel that obligations to pay auditors, as with any suppliers, should be a managed through commercial arrangements and contract management. Requiring payment via regulation appears to verge on regulatory overreach, as well as providing auditors with greater protections than other industry participants.

CODE AMENDMENT	ENA COMMENT
CRP6-012 Align annual reporting requirements for AUFLS	ENA supports the intent of this proposed change, because it supports simplification and alignment.
CRP6-013 Timing of a change to a NSP creation date	ENA supports the intent of this proposed change, because it provides greater clarity.
CRP6-014 Dates for auditor biennial rotation	ENA supports the intent of this proposed change, because it provides greater clarity. However, we do note that the rotation requirements are more onerous for EDBs than for NZX listed companies and Public Interest Entities (PIEs). The Authority may wish to reconsider whether this is the outcome they were intending and perhaps consider a more risk-based approach to determining audit frequency going forward.

If you have any questions about ENA's submission please contact Gemma Pascall, Regulatory Manager (gemma@electricity.org.nz).

Yours sincerely

GPascall

Gemma Pascall

Regulatory Manager

Appendix A: ENA Members

Electricity Networks Aotearoa makes this submission along with the support of its members, listed below:

- Alpine Energy
- Aurora Energy
- Buller Electricity
- Centralines
- Counties Energy
- Electra
- EA Networks
- Firstlight Network
- Horizon Networks
- Mainpower
- Marlborough Lines
- Nelson Electricity
- Network Tasman
- Network Waitaki
- Northpower
- Orion New Zealand
- Powerco
- PowerNet (which manages The Power Company, Electricity Invercargill, OtagoNet and Lakeland Network)
- Scanpower
- Top Energy
- The Lines Company
- Unison Networks
- Vector
- Waipa Networks
- WEL Networks
- Wellington Electricity
- Westpower