Meeting Minutes

Meeting name:	**ERS Workshop 3**
Date, time & location:	23 June 2026, 9am–1pm, EA offices and Microsoft Teams

Attending

Name	Role
Peter Algie	Group member, Ritchies Transport
James Carberry	Group member, Simply Energy
Alan Eyes	Group member, NZ Steel
Michael Jefferson	Group member, Enel X
Craig Parker	Group member, Mercury Energy
Darren Gilchrist	Group member, Oji Fibre Solutions
Marcus Sin	Group member, Counties Energy
Vincent Smart	Group member, EECA
John Hancock	Independent Chair
Murray Henderson	Transpower, Principal Market Advisor
Bridget Legg	Transpower, Contracts & Reporting Specialist
Michael Richardson	Transpower, Flexibility Services Manager
Andrew Marriott	Electricity Authority (observer)
Bridget Moon	Secretariat (independent)

There were no apologies. Alan Eyes listened in but did not participate in the meeting.

Introduction and context

The Chair opened the third ERS Co-design Group workshop with housekeeping, a recap of prior sessions, and an outline of the day's aims.

Murray Henderson outlined the SO's development timeline, noting that procurement plan consultation is targeted for late August, and clarified that it will be the only formal consultation process.

He then presented the SO's proposed design features for the group's feedback. This built incrementally on workshop 2 and included positions on issues that had previously attracted significant discussion.

Discussion in response to the SO's proposals

Forecasting the need: The SO proposed focusing its year 1 needs assessment on the May to September period.

The group noted that the marginal cost of extending this to October would likely be minimal, but that extending it to a full-time service was beyond the scope set by the EA, which set procurement for three to six months. The group agreed that the market should generally rely on its existing tools.

The group therefore broadly supported an approach that covered the six months between May and October.

Eligibility: The SO proposed eligibility limitations that would align with the Code's 'additionality requirements', plus an explicit exclusion for hot water load control and load on networks with automatic control limits.

The group broadly agreed in principle that:

- All hot water load control should be excluded as non-additional, consistent with the EA's intent.
- Grid-scale batteries should be excluded, but behind-the-meter batteries used on-site by an ERS provider should not, in line with the Authority's Code changes.
- While load participating in other markets should be excluded, there may be load behind the same ICP that should be eligible, as long as the actions of both can be separately verified, for example through sub-metering.
- Excluding load on networks with automatic control limits is pragmatic for year 1, though it could preclude some valuable providers and networks vary in their degree of control. The SO could consider a more comprehensive approach in future, potentially including tripartite contracting arrangements involving load and an EDB with an automated network response.

Overall, the group broadly supported the SO's approach, but suggested that the SO needs to include very clear guidance in its consultation paper on:

- which resources are explicitly included and excluded from participation in the ERS
- its expectations around ring-fencing and stand-down from other markets.

The consultation paper needs to provide enough detail to give clarity in instances such as those identified by the group, and where 'additionality' may not be clear-cut.

Baselining: The SO proposed a 'high-trust' approach to the scheme, in which it would assess provider capability and reliability, rather than set a baseline for individual loads.

The group acknowledged the difficulty of baselining across a diverse range of loads. However, it noted that standardised approaches exist in other jurisdictions and in FlexPoint, and that the particular method used could be agreed through contracting.

In previous workshops, the group had identified baselining as a primary opportunity for gaming the scheme. The group further discussed:

- The potential for load to participate in both ER and interruptible load markets without detection, given the low probability of both services being called simultaneously.
- The need to ensure parties can't game a baseline by shifting load onto a different feeder that is not subject to the baseline or post-event checks and balances — an issue that is explicitly addressed in the equivalent scheme in Western Australia.
- The legitimacy of providers adjusting their offered volume at pre-activation to reflect conditions such as weather or maintenance. It was suggested that the SO may need a way to allow this. A bid-based system was floated, but was seen as too complex.

The group generally considered that a 'high-trust' approach, including director certification and potential auditing, is a pragmatic approach for year 1 of the ERS, noting the group's view formed during workshop 2 that aggregators may be the most appropriate ER providers.

Penalties: Under the SO's 'high-trust' approach, non-payment and/or clawback of availability payments would be the main consequence of non-delivery.

The group discussed whether clawback provided sufficient incentive for effective ER delivery.

It considered that penalties should be proportionately lighter than for other ancillary services given that non-delivery simply reverts to the status quo, making non-performance less consequential than for other ancillary services. It also agreed that reputational concerns, contract provisions, director certifications, and auditing would be effective for disciplining performance.

The group discussed how clawbacks may need to differ according to timing, scale, or duration of response. It was generally agreed that the clawback could be linear with regard to scale, but potentially not with regard to timing or duration, as a late response would likely be ineffective for avoiding load shedding. It was agreed that the SO would need to be clear on performance expectations on each of these dimensions, and ensure providers are sufficiently incentivised to provide what the SO actually wants and expects to be delivered.

Overall, the group broadly agreed that a 'high-trust' approach could be appropriate for the first year of the ERS, but that the SO needs to appropriately balance pragmatism and the integrity of the service through very clear performance expectations and effective but proportionate penalties.

Response duration: Following workshop 2 feedback, the SO proposed a maximum response duration of three hours.

The group identified the possibility that longer responses could be required, given manual load restoration and the demands on the SO when coordinating multiple resources. Three hours was seen as a pragmatic maximum response duration, with any additional time potentially provided on a best-endeavours basis rather than as a firm contractual commitment.

National product: The SO proposed that procurement of ER would be on a national basis. It noted that South Island responses can address North Island shortfalls because a reserve shortfall should occur before ER is called, meaning the HVDC would not be reserve-constrained.

The group considered that capacity scarcity is most likely to affect the North Island, and that North Island capacity constraints could result from an HVDC outage, which is a significant system risk. It therefore considered that a North Island-based response was likely to be more valuable than a South Island-based response. However, it considered that a South Island response could still be valuable and excluding it could reduce competition to provide ER.

On balance, the group generally agreed that ER should be procured on a national basis, but that the SO might consider a provider's location when assessing tenders.

Payment structure: Following the discussion at workshop 2, the SO proposed that it would tender for ER based on availability payments only to simplify tendering, particularly for year 1.

The group saw merit in simplicity, but considered an event-based payment could have benefits in terms of:

- Signalling the marginal cost of ER use, which would help the SO when activating ER and discipline its use.
- Giving providers greater certainty of recovering their costs if there are more events than expected, resulting in greater willingness for sites to participate in the scheme.
- Likely resulting in lower overall costs, given the probability of an event is very low, and that relying only on an availability-based payment would lead providers to charge a premium for uncertainty they are not well placed to assess.

The group discussed whether event payments would amount to paying twice, given that reducing load during scarcity already has monetisable value through the spot market. It discussed the difficulty for ER providers accessing that value, as it depends on aggregators and retailers being willing to pass it through, and negotiating with them to that end. It was also noted that plant constraints mean an ER provider's response may extend beyond the period of scarcity pricing, so the avoided costs may not align with its incurred costs.

Overall, the group preferred an approach that included both availability and event-based payments. It suggested event-based payments should be on a per-MWh basis, covering the full trading period in which a response is required, even if it is only required for part of the trading period.

To aid tendering, the group suggested the SO indicate an expected and maximum number of events. The group identified a risk in indicating a maximum, given the possibility of more events than indicated. While the risk would be minor, the SO would need to make it explicit.

Pre-activation and activation triggers: The SO proposed that pre-activation would occur when the NZ or North Island residual was less than 100 MW, and activation would occur when it was less than 0 MW.

In response to questions, the SO noted that the chances of going from pre-activation to activation would depend on its proposed thresholds, which will be informed by further analysis. The group

sought clarification on the sequence of other SO actions in such situations, including the use of hot water load control. The SO stated that many actions are currently based on judgement (though that may change), but that the control room could not accommodate more manual decision-making and required ER to be an automated process.

The group discussed concerns including:

- Pre-activation may not be costless and could warrant its own payment stream, particularly if frequent.
- Frequent pre-activation could generate a 'boy who cried wolf' effect, prompting media attention and informal public conservation responses.
- Whether 100 MW is sufficient to manage intermittency risks, given how quickly wind generation can drop off, and that pre-activation calls would be made 24 hours ahead of time.
- The need for pre-activation and activation to be public information so all parties have equivalent information.

The group considered the SO should make the implications of its thresholds very clear in its consultation materials, by presenting analysis of historic residuals and clarifying interactions with other emergency responses. It also supported public notification of pre-activation and activation.

Next steps and wrap-up

The Chair indicated that a fourth workshop was unnecessary as the group had covered all the intended material. He thanked participants for their engagement throughout the co-design process.

Group's view on the SO's proposed design

"The Co-design Group appreciates the opportunity to contribute to the design of the Emergency Reserve Scheme ahead of formal consultation. Members found the process well-run and collaborative. The System Operator presented its thinking openly across three workshops, engaged very constructively with the Group's questions and concerns, and demonstrated a willingness to revisit its positions in response to feedback.

The workshops surfaced important design questions early and more constructively than formal consultation alone would have achieved. The group considers that its discussions led to meaningful insights, such as identifying that the scheme may realistically lend itself more to aggregators with a portfolio of DR resources, rather than to individual providers, and that the System Operator should articulate what it needs the service to provide, rather than trying to anticipate what might be provided. The Group recognises that there are some difficult trade-offs to consider in the scheme's design, and that year 1 of the scheme justifies pragmatic decisions that may not reflect the ideal long-run design.

Individual Co-design Group members may choose to take a different position on specific aspects of the proposed design. However, the Group is broadly supportive of the direction the System Operator is taking. Members acknowledge that several design details remain to be worked through at the level of detail necessary for the procurement plan and tender documentation, and that some

members may have feedback on those specifics when they are published. The Group looks forward to engaging further through the formal consultation process."

Actions

ID	Description	Owner	Due by
1	Share the slide pack and minutes with participants.	SO team	8 July
2	Minutes to include a statement from the group on its views on the design and the co-design process.	SO team	23 June

Parking lot / issues for later resolution

ID	Description
1	**Ripple control and the contestability of controllable load.** The multiple and evolving ownership arrangements around ripple-controlled load, and the question of whether the priority given to different uses is appropriate, may extend beyond the ERS design, though the group may wish to consider whether ripple control should be explicitly excluded from the scheme.
2	**Contract length and investment certainty.** The tension between a short contracting horizon to manage costs on behalf of purchasers and the multi-year certainty that prospective providers may want to justify investment in DR capability was not resolved.
3	**The ERS as a capacity payment.** The concept of the ERS representing a first step toward broader capacity payments, and the implications of that for flexibility resources outside the ERS, are beyond the scope of the group.
4	**Co-optimisation of ERS with energy and reserve markets.** The ERS is not co-optimised with other market services, meaning there is potential for flow-on impacts if ERS participation cannibalises other markets. The additionality principle is an imperfect solution to this problem, and may become less effective as the ERS matures and DR resources grow.