Establishing an Emergency Reserve Scheme

Consultation paper

31 July 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is considering establishing an emergency reserve scheme (ERS) to enhance the reliability of New Zealand's electricity system and support security of supply.

The ERS was set out in our proposed roadmap for industrial demand flexibility, developed by the Energy Competition Task Force, as a potential 'immediate action' to take. Submissions on this roadmap indicated many stakeholders were supportive of the proposal to develop an ERS. Several stakeholders identified issues to be considered in the scheme design.

This paper seeks your feedback on the Authority's rationale for implementing an ERS scheme in the New Zealand electricity market, and on high-level design options. The feedback will inform our decision on whether to proceed with this type of scheme.

Should the Authority choose to proceed with an ERS, we will consult further on changes to the Electricity Industry Participation Code (Code), required for its implementation.

Supporting electricity system reliability and security of supply

The increasing share of intermittent capacity in New Zealand's electricity generation mix is creating challenges for security of supply – especially on cold, still mornings and evenings (known as 'peak capacity risk'). Growth in electricity demand and the declining availability of thermal fuel for generation (especially gas) are exacerbating this risk. The System Operator's assessments of security of supply suggest peak capacity risks will continue until there is sufficient investment in flexible resources, such as batteries and demand flexibility.

Existing market mechanisms provide sufficient price signals for investment in, and operation of, the electricity system to manage peak capacity risk and balance the system under normal conditions. However, in limited circumstances – such as a combination of high demand and a high level of unplanned outages – there is a risk that the market will not balance supply and demand. There are a range of tools available to the System Operator in these situations, with the aim of avoiding the last resort of involuntary disconnection of consumers.

All consumers should have electricity when they need it, without regular or prolonged power cuts. The Authority has a broad programme of work to support security of supply, including managing peak demand periods.

An ERS could provide an additional tool for the System Operator to use in periods of acute system stress. It would promote power system reliability and security by helping to manage critical supply shortfalls and could avoid consumers' power being disconnected during emergency events.[1] It is not intended to be a solution to address long-duration events causing system stress, such as dry years.

We propose to establish an emergency reserve scheme as a 'penultimate resort'

We propose to establish an ERS as a mechanism for the System Operator to activate as a 'penultimate resort' (ie, prior to involuntary disconnection) using pre-contracted demand flexibility. We expect other forms of demand flexibility to be used ahead of an ERS (including controllable load). Emergency reserve mechanisms are used in several international

[1] From a technical perspective, we would refer to this as 'uneconomic' load shedding, a situation where supply is cut to consumers who would have been willing to pay a price higher than spot market price to avoid an outage. Where emergency reserves can be activated at a lower cost than the value to consumers of avoiding an outage, an ERS can support efficient market outcomes.

jurisdictions to help manage peak capacity risk (including Australia, the US and UK), and we would draw lessons from these in designing a scheme for the New Zealand market.

The Authority's view is that an ERS could unlock latent demand flexibility (which currently faces insufficient market incentives), improving system efficiency and reliability. Better use of demand flexibility is likely to cost less than investing in additional supply for infrequent use.

Additionally, and in keeping with our draft roadmap for industrial demand flexibility, an ERS could help build demand-side capability among consumers. This would unlock greater potential for the provision of short-term flexibility services outside of emergency situations.

If we proceed with an ERS, we would aim to have it in place by May 2026, so it is in for winter 2026. This would help mitigate security of supply risks next year, such as those set out in Transpower's Security of Supply Assessment 2025.

Our proposed scheme design will benefit consumers while minimising risks

Our ERS design aims to deliver benefits to consumers through enhancing security of supply and efficiency, while minimising the risks of market distortion. The design seeks to:

- minimise distortions to the operation of the wholesale market, by ensuring flexibility services procured are additional, activation is triggered only after exhausting market-based options, and scarcity price signals are maintained
- maximise the benefits of competition within-scheme, by keeping compliance costs low and pricing structures flexible to encourage participation from eligible providers
- minimise overall costs, by leveraging existing processes where possible and capping service costs at the value of lost load.

We propose to allow a wide range of demand flexibility sources to participate in the scheme, including large industrial consumers and aggregations of smaller consumers and industrials.

In our Rewarding industrial demand flexibility paper, we identified up to around 170MW of industrial demand flexibility capacity. This scale of demand response could have a meaningful impact when supply is tight. Aggregated demand flexibility from smaller consumers has also been tested in the Winter Peak Innovation Pilot, and has operated in similar reserve mechanisms in Australia and the UK. As demand grows and demand-side capabilities mature in the future, we anticipate the capacity for demand flexibility from all types of consumers will grow.

At this stage, we are not proposing to include other resources such as grid-scale batteries or off-market generation in the scheme. Our expectation is that these types of resources would generally be used before the ERS is activated and receive the wholesale market price for doing so. We welcome any feedback and information submitters could provide on this point.

Next steps

The Authority welcomes your feedback on this consultation paper by 28 August 2025. Your views will help inform whether we progress with the implementation of an ERS.

Should we proceed with the ERS concept, we plan to publish a consultation paper in late 2025 on proposed Code changes, with the goal of having the scheme commence in time for winter 2026 (subject to feedback, final design decisions and implementation considerations).

We envisage that staged implementation may be required, moving to full implementation of the design features proposed in this paper as participants gain experience with the scheme.

Contents

1. How you can inform our thinking

What this consultation is about

1.1. The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on:

(a) a proposal to implement an emergency reserve scheme (ERS) in the New Zealand electricity market

(b) potential design options for such an ERS scheme.

1.2. Most of the time, the wholesale electricity market provides effective price signals for market participants to invest in and operate electricity supply to meet consumer demand and manage risks such as planned and unplanned outages.

1.3. However, infrequent events can arise when very high demand coincides with limited supply (eg, due to plant outages and low wind generation). In these instances, involuntary disconnection or 'load shedding' operates as the last resort mechanism to maintain the supply-demand balance and security of the power system.[2] This significantly reduces the likelihood of system collapse, avoiding widespread blackouts, and ensuring the system can quickly recover.

1.4. While this supports the stability of the electricity system, it is not a good outcome for affected consumers, particularly in the middle of winter. The Authority's view is that involuntary disconnection of consumers needs to be an absolute last resort. The last notable example of involuntary load shedding to balance supply and demand was on 9 August 2021, when around 34,000 consumers were disconnected on the coldest night of the year. The Ministerial review of this event found that this load shedding did not need to occur.[3]

1.5. We are keen to make sure that the right mechanisms are in place to ensure that load shedding is genuinely a last resort. This paper sets out our proposal to establish an ERS in New Zealand to act as a 'penultimate resort' to support electricity system reliability and security of supply. It would sit between market-based resolution and the System Operator instructing electricity distribution businesses (EDBs) to reduce demand (ie, emergency load shedding).

1.6. The ERS would draw on pre-contracted flexibility from consumers to reduce demand by a specified amount, if supply is imminently forecast to not meet demand. Operating before the System Operator calls for reductions, an ERS would avoid or reduce load shedding and the resulting impacts on homes and businesses.

1.7. To be able to participate in the ERS, a demand-side provider would have to show that the response is additional (ie, that the load would not otherwise respond to these events). The provider would be compensated for the role they play in supporting the reliability of electricity supply for consumers.

1.8. We consider demand flexibility can deliver value in these circumstances, offering an efficient solution compared to the cost of additional supply for brief, infrequent use.

[2] The System Operator is authorised to instruct participants to take certain actions in an emergency to ensure stability of the power system, including the disconnection of some consumer demand.
[3] Finding 1 of the Investigation into electricity supply interruptions of 9 August 2021

1.9. The Authority indicated its intention to develop a proposal for an ERS in the *Rewarding industrial demand flexibility – issues and options paper* (issues and options paper), developed through the Energy Competition Task Force, released on 28 May 2025.

1.10. This ERS consultation paper builds on our thinking outlined in the issues and options paper. It sets out:

(a) what an ERS is

(b) the rationale for establishing an ERS

(c) examples of emergency reserve mechanisms in other electricity markets

(d) proposed objectives and a high-level design for an ERS for New Zealand.

1.11. Our proposed design has been informed by advice from Robinson Bowmaker Paul (RBP). RBP's report (Appendix A) considered several alternative options for elements of the ERS design.

1.12. Given the technical nature of the subject matter covered in this paper, we have provided a glossary of key terms in Appendix D.

How to provide feedback

1.13. We prefer to receive feedback in electronic format (Microsoft Word) in the format shown in Appendix C. Please email your feedback to taskforce@ea.govt.nz with 'Establishing an Emergency Reserve Scheme' in the subject line.

1.14. If you cannot send your submission electronically, please contact the Authority at taskforce@ea.govt.nz or 04 460 8860 to discuss alternative arrangements.

1.15. Please note that the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published and explain why we should not publish that part

(b) provide a version of your submission the Authority can publish (if we agree not to publish your full submission).

1.16. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.17. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority could be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you indicated should not be published.

1.18. In addition, please note the Authority may share submissions or other information, including parts of submissions not published, with another public service agency, statutory entity, the gas industry body or an overseas regulator in accordance with section s47A of the Electricity Industry Act 2010. The Authority would only do so if the submissions or other information could assist that organisation in the performance of its functions, and if it is satisfied that are appropriate protections in place for maintaining the confidentiality of anything provided (including information that is personal within the meaning of the Privacy Act 2020).

When to make a submission

1.19. Please deliver your submission by 5pm, 28 August 2025.

1.20. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority at taskforce@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Context for this work

The Task Force is exploring ways to ensure that industrial flexibility is adequately rewarded, to support security of supply

2.1. The Authority and Commerce Commission Te Komihana Tauhokohoko (Commission) jointly established the Energy Competition Task Force (Task Force) in response to the shortage of fuel, and period of sustained high wholesale prices, in August 2024. The Task Force is focused on several measures to promote competition in the market and support security of supply.

2.2. As part of its work programme, the Task Force is exploring how to better reward industrials for short-term demand flexibility (eg, intra-day flexibility), to support electricity system reliability and security of supply.[4] In the Authority's view, the opportunity this form of flexibility presents is not being fully realised under current market settings.

2.3. We are focused on short-term flexibility, which minimises the impacts on industrial economic activity, as opposed to longer-term seasonal demand response. Because it requires less substantial and shorter shifts in demand, it can come at a much lower cost to productive economic activity. Both industrials and the wider electricity market could benefit from measures to unlock this type of flexibility.

Our industrial flexibility roadmap set out our intention to develop an emergency reserve scheme ahead of winter 2026

2.4. On 28 May 2025, we released an issues and options paper on industrial demand flexibility for consultation. The paper outlined a proposed vision and five-year roadmap of actions to enable greater use of industrial demand flexibility and support a more reliable and efficient electricity supply.

2.5. In the paper, we indicated that we were considering establishing an ERS in which industrial demand flexibility could participate, and that we would shortly consult on this proposal, to enable the scheme to be in place for winter 2026.

2.6. This *Proposal for an emergency reserve scheme – consultation paper* (ERS consultation paper) seeks feedback specifically on the need for an ERS in New Zealand, and high-level design options for such a scheme.

Feedback received on the industrial demand flexibility issues and options paper and the proposal to implement an ERS

2.7. We received 21 submissions on the issues and options paper from a range of stakeholders, including industrial consumers, EDBs, the System Operator, retailers, generators, a demand response service provider and representative bodies. The issues and options paper and its submissions can be found on our website.

2.8. Submissions generally supported the Task Force's and Authority's intent to enable the efficient provision of flexibility services in New Zealand's electricity market and canvassed a wide range of issues and suggestions. We are currently considering

[4] For this work, 'industrials' includes industrial and larger commercial electricity consumers, including consumers not directly connected to the transmission network and which may operate over several sites.

this feedback in detail to inform the next steps for our proposed industrial demand flexibility roadmap.

2.9. Of the submitters that commented on the proposed ERS, most indicated support for such a scheme. Of those who did not support it, this view generally reflected either concerns that an ERS could risk undermining the existing market, or a preference for the Authority to prioritise other work.

2.10. We acknowledge these issues, and we have set out further information on:

(a) the need to consider implementation of an ERS now

(b) proposed design features to help mitigate impacts to the existing market from implementation of an ERS.

2.11. Many submissions also identified issues to be considered through scheme design. This feedback has been helpful in our consideration of the high-level design of the scheme, and we have referenced these points in the relevant sections of this paper.

An emergency reserve scheme aligns with our proposed vision and roadmap

There is an opportunity for demand flexibility to contribute to a reliable and efficient electricity system, particularly during periods of system stress

2.12. In our issues and options paper, we identified around 170MW of high-confidence potential industrial demand flexibility.[5] While modest, at around the scale of a medium-sized power plant, this could make a meaningful difference in managing short, infrequent periods of acute system stress because:

(a) at these times, even relatively small volumes can make a material difference to the cost and reliability of supply

(b) the incentives required to provide demand flexibility for such situations may be less than the cost of additional supply-side investments

(c) the use of industrial demand flexibility to help manage infrequent, short-duration incidents of acute system stress will have a relatively modest impact on the broader economy (compared to seasonal demand response).

2.13. We anticipate the potential for industrial demand flexibility to grow over time as new industrials and industries (such as data centres) come online and the maturity of existing and emerging demand-side technologies increases, and in response to our actions.

2.14. We recognise that demand flexibility may be currently underutilised under existing settings. Current incentives tend to be limited to avoided energy costs, and existing market mechanisms such as Dispatchable Demand (DD) have not been successful in getting industrials to participate – with the cost of providing flexibility (including opportunity cost of foregone production) often higher than the available incentive.

[5] See Section 4 of the issues and options paper. The Authority engaged Sense Partners to assess the scale of industrial demand flexibility currently available, and the size of incentives required by industrials to provide intra-day demand flexibility.

Our proposed vision and roadmap for industrial demand flexibility

2.15. The issues and options paper set out our proposed vision: To enable efficient industrial demand flexibility so it achieves long-term benefit for consumers by promoting a competitive, reliable, and efficient electricity industry.

2.16. As the paper set out, providing incentives that exceed the value of avoided energy costs can be considered 'efficient', where the benefit of flexibility to the system exceeds the cost, and demand flexibility is lower cost than an alternative option.

2.17. This could unlock a greater level of demand flexibility and benefits for both flexibility providers and other consumers, reducing the incidence or extent of high prices (and exposure to these), and supporting overall system reliability and security of supply.

2.18. The proposed roadmap in the issues and options paper set out a targeted, and escalating, series of actions to unlock industrial demand flexibility and lay the foundations for greater demand-side flexibility in the system more broadly.[6]

2.19. The first action on the roadmap is to investigate establishing an ERS to make better use of existing industrial demand flexibility to support electricity system reliability and security of supply, particularly ahead of winter 2026.

2.20. The Authority is considering the establishment of an ERS as a targeted backstop mechanism. As outlined in the issues and options paper, the Authority does not yet consider there is a case for the introduction of further, new paid demand flexibility mechanisms. We are currently considering feedback on the issues and options paper and will advise on next steps in due course.

While this work has focused on industrial demand flexibility to date, we recognise the value that other forms of flexibility can offer the power system

2.21. While our issues and options paper focused on industrial demand flexibility, we acknowledge the growing potential for demand from smaller consumers to be aggregated to provide flexibility services to the wider market.

2.22. We are open to considering participation in an ERS by all consumer types, ranging from large industrials to aggregations of smaller consumers (see Section 5.30). Aggregated demand flexibility from smaller consumers has been tested in New Zealand through the Winter Peak Innovation Pilot. It has also been used in emergency reserve mechanisms in other jurisdictions, including in the UK and Western Australia (discussed further in Section 3 below).

2.23. We have also considered whether other forms of flexibility, such as from off-market generation and batteries, should be able to participate in the scheme. We are concerned that the inclusion of these resources may distort incentives in the wholesale electricity market and may not provide additional capacity to enhance reliability in the system.

2.24. We acknowledge, however, that several submissions to the issues and options paper suggested that all forms of flexibility should be considered by the Authority, for the proposed ERS and more broadly.[7] We welcome further feedback from

[6] See Appendix A of the issues and options paper.

[7] See for example, submissions from Business Energy Council, Counties Energy, Meridian Energy, Octopus Energy, Powerco and Vector.

stakeholders on this issue specifically in the context of an ERS (see Section 5.38 below).

The scheme fits with the Authority's wider work to promote flexibility, resilience and security of supply, for the long-term benefit of consumers

2.25. The Authority is working to strike a balance between providing the System Operator with sufficient flexibility to manage power system security, and promoting appropriate market signals to incentivise reliable supply for consumers, including during periods of high demand and tight supply.

2.26. This includes implementing recommendations from the Market Development Advisory Group (MDAG) on the evolution of the wholesale electricity market, as well as recommendations from a review of the 9 August 2021 load shedding event.

2.27. These market strengthening initiatives have focused on three key areas:

(a) **improvements to information about the supply-demand balance** (residual generation levels) – eg, improving information for market participants about headroom in the supply stack and the sensitivity of forecast spot prices to demand variability; improving System Operator information about the availability and use of controllable load by EDBs, in mid-2023[8] as part of our work on managing peak electricity demand; improving outage coordination from late 2024; improving access to thermal fuel information from April 2025; and improving intermittent generation forecasts and offers from 31 July 2025

(b) **improvements to the incentives for supply-side and demand-side resources** to participate when the supply-demand balance is tight – eg, updates to scarcity price settings implemented in April 2025

(c) **initiatives that support risk management by market participants** – eg, the new standardised super-peak hedge product, which began trading January 2025.

2.28. The Authority's future security and resilience workstream focuses on ensuring the power system remains secure and resilient as it transitions to increasing levels of variable and intermittent generation. This includes our future security and resilience indicators published in May 2023, consultation on ensuring an orderly thermal transition, reviewing the future operation of the power system, and reviewing common quality requirements in Part 8 of the Electricity Industry Participation Code (Code).

2.29. The Authority is planning to review the settings for the value of lost load (VoLL) and system security in the Code, to ensure they can effectively facilitate planning and operational decisions to support efficient and reliable electricity supply. These market settings, particularly VoLL, play a key role in determining the need for and assessing offers to provide emergency reserves (discussed further in Section 7).

2.30. The Authority also continues to deliver a wider programme of work focused on enabling greater use of demand flexibility. This includes our decentralisation green paper (released in May 2025), our support for industry trials through our Power

[8] These were initially made as temporary, urgent changes, and confirmed in 2024 as permanent changes.

Innovation Pathway, and work aligned with the recommendations of FlexForum's *Flexibility Plan 2.0.*[9]

2.31. More broadly, many elements of the Authority's work programme will contribute to a more secure and reliable electricity supply for New Zealanders. This includes work to improve access to flexibility services, support investment in new large-scale generation and storage, improve distribution pricing and connections, and provide more options for electricity consumers.

The System Operator continues to enhance planning and preparedness

2.32. Since 2022, the System Operator and Authority have made improvements to communication tools and processes, and accountabilities, to enhance system planning and preparedness. These include updates to the System Operator's processes and operational notices for insufficient generation; updated guidance and documentation on how the System Operator manages low residual situations; annual industry-wide simulation exercises to practice managing a hypothetical grid emergency; updates to the System Operator rolling outage plan; and work to strengthen Authority oversight of the System Operator.

2.33. The System Operator is also continuing to improve its demand and supply forecasts, along with processes for scheduling and dispatch in the wholesale market. In addition to seeking stakeholder input into its annual Security of Supply Assessment (SOSA), the System Operator has provided guidance to market participants on accuracy of bids and offers in the Week-ahead Dispatch Schedule; consulted on its processes for scheduling and dispatch; and is currently reviewing the *Security of Supply Forecasting and Information Policy*.

[9] Available at https://flexforum.nz/flexibility-plan/. This includes rule changes to improve visibility of network capacity and constraints; moving towards real-time access to consumer data and enabling consumers to have more than one retailer for different services (consultation paper released in June 2025); and making it faster and easier for distributed generation to connect through our network connections project.

3. What is an emergency reserve scheme?

3.1. An ERS is intended to help maintain power system security and reliability during rare periods when supply shortfalls arise, to minimise the risk or extent of uneconomic load shedding. These types of schemes typically involve a party such as a market or system operator entering contracts with unused or off-market supply sources (often in the form of demand response), which can be activated to manage a supply shortfall.

3.2. An ERS is generally a 'penultimate resort' scheme. It is intended to operate after all spot market and pre-contracted supply sources (including pre-contracted demand flexibility and controllable load) have been exhausted, and the only remaining option to ensure system security and reliability is involuntary load shedding. An ERS provides a mechanism that can be activated by the System Operator to avoid uneconomic load curtailment.

3.3. An ERS is intended to be used infrequently and for short periods of time (eg, a couple of hours). It is not intended to be a solution to address long-duration events causing system stress, such as a dry year. Other mechanisms such as contingent hydro storage and Official Conservation Campaigns (OCCs) are used to manage these longer duration events.

International examples of emergency reserve mechanisms

3.4. Several electricity markets around the world operate emergency reserve mechanisms, including both 'energy-only' markets like New Zealand and those with a capacity mechanism. Some examples are summarised below, setting out key design features including who is eligible to provide emergency reserves and how they are procured and activated.

Australia National Electricity Market – Reliability Emergency Reserve Trader

3.5. The Reliability Emergency Reserve Trader (RERT) enables the Australian Energy Market Operator (AEMO) to contract for reserves to maintain power system security and reliability. The RERT has been a feature of Australia's National Electricity Market (NEM) since it commenced in 1998. Both supply- and demand-side resources that are not otherwise available in the market can participate.

3.6. AEMO can contract RERT in a region when it is declared to have a 'lack of reserve' condition within the coming 12-month period.[10] RERT can be contracted over three-time horizons:

(a) **long notice** (between 12 months and 10 weeks from a projected shortfall) – AEMO will undertake a tender process with prospective suppliers

(b) **medium notice** (between 10 weeks and seven days from a projected shortfall) – AEMO requests offers from a pre-qualified panel of suppliers who can negotiate prices when a shortfall is forecast

(c) **short notice** (less than seven days from a projected shortfall) – AEMO also requests offers from its pre-qualified panel, using pre-offer prices.

[10] Lack of reserve notices are summarised in AEMO's factsheet.

3.7. If a forecast shortfall eventuates, AEMO can dispatch RERT as a last resort. Dispatch of RERT happens outside normal market clearing and dispatch processes. When RERT is dispatched, AEMO will adjust spot prices for the affected intervals to the levels they would have been if not for the intervention.

3.8. AEMO has contracted RERT every year since 2018-19 in one or more regions of the NEM. In 2023-24, AEMO procured between 189MW and 343MW across three occasions, accounting for up to 3% of peak demand levels on the relevant days. These contracts were not activated, and no costs were incurred. By contrast, in 2022-23 AEMO contracted for a total of 318MW for a single activation at a cost of AUD2.06 million (approximately NZD2.25 million).

3.9. AEMO cannot contract RERT at a cost greater than the value of customer reliability (also referred to as VoLL). RERT contracts can include payments for availability, pre-activation, activation and early termination, and costs are recovered from market customers. No payment is made for being part of the RERT panel.

3.10. Further information on RERT is available in RBP's *Demand Response Programmes – International Scan* report, published in conjunction with our industrial flexibility issues and options paper, and from the AEMO website.

Western Australia – Supplementary Capacity

3.11. Supplementary Capacity is a mechanism that can be triggered by AEMO in Western Australia's Southwest Interconnected System (SWIS) to maintain power system security and reliability. Supplementary Capacity has been a feature of the SWIS wholesale electricity market since it commenced in 2006.

3.12. Supplementary Capacity can be contracted within six months from the start of a 'hot season' (1 December to 31 March), when peak demand typically occurs, if AEMO forecasts a capacity shortfall. If AEMO identifies the shortfall at least 12 weeks before the hot season, it must undertake a tender process. If the shortfall is identified within 12 weeks before the hot season AEMO may either undertake a tender process or negotiate directly with potential providers.

3.13. Both supply- and demand-side resources can provide Supplementary Capacity, with some restrictions, including where the provider holds (or has held) Capacity Credits. This is to minimise potential for providers to withhold capacity from the Reserve Capacity Mechanism, which is the primary market mechanism to ensure reliability of supply in the SWIS.

3.14. Like RERT, if the forecast shortfall eventuates, AEMO can dispatch Supplementary Capacity, and its activation is not integrated into market clearing and dispatch processes. Prices in the real-time market are not adjusted to 'add back' the impact of any demand reduction provided by Supplementary Capacity, meaning it can have the effect of lowering the wholesale market price.[11]

3.15. Supplementary Capacity has been procured on four occasions: 2008-09, 2022-23, 2023-24 and 2024-25, and has been activated in each of those years except 2008-09. Most recently, AEMO contracted 198MW of Supplementary Capacity for 2024-25, which represents around 4.4% of the maximum demand recorded in the

[11] However, as a capacity mechanism is in operation, prices in the real-time market make a weaker contribution to investment signals when compared to an energy-only market.

SWIS that hot season. Supplementary Capacity was activated on five occasions at a total cost of AUD24.9 million (around NZD27 million).[12]

3.16. AEMO seeks to procure Supplementary Capacity at a lower cost than the value of customer reliability. Providers can seek availability and activation payments, or only activation payments. If a provider fails to provide some or all its capacity it does not receive payments for the relevant period. Costs are allocated to market customers in the same manner as Reserve Capacity Mechanism costs, which are proportionate to the customer's share of consumption during peak demand periods.

3.17. More information about Supplementary Capacity is available from the AEMO website and in Energy Policy WA's Supplementary Capacity reviews.[13]

Texas – Emergency Response Service

3.18. The Electricity Reliability Council of Texas (ERCOT) procures the Emergency Response Service (TERS) to decrease the likelihood of system-wide load shedding in an electric grid emergency. TERS has been operating since 2007, with loads and off-market generators (including aggregations) eligible to provide the service.

3.19. ERCOT procures the service via competitive tender and is permitted to procure TERS up to a maximum annual figure, currently USD75 million[14] (around NZD125 million). Payments can involve availability and activation payments.

3.20. Tenders are run for four periods across the year: December to March, April and May, June to September and October and November. Services are sought across four categories based on whether the resource is weather sensitive or not, and a response time of either 30 minutes of 10 minutes.[15]

3.21. The best-known use of TERS was during Winter Storm Uri in February 2021. During this event, the majority of the TERS fleet was deployed and exhausted within 12 hours of deployment and TERS loads generally met or exceeded their obligations.

3.22. More recently, during high demand conditions on 13 July 2022, ERCOT activated the TERS for approximately 3.25 hours resulting in a demand reduction of just over 1,000MW, or around 1% of peak demand levels.[16]

Great Britain – Demand Flexibility Service

3.23. The Demand Flexibility Service (DFS) was introduced in Great Britain for Winter 2022-23. DFS was established to enable the system operator (now the National Energy System Operator, NESO) to access demand response as an 'enhanced action' in addition to normal electricity market supplies, during periods of high demand when the electricity system is under stress.

[12] AEMO, *WA Electricity Consultative Forum*, 8 May 2025, Slide 27

[13] The Wholesale Electricity Market Rules require that a review of the Supplementary Capacity mechanism be undertaken each time it is used. See, for example, information about the 2024 Supplementary Capacity Review.

[14] See clause 25.507(b)(2) of the Electric Substantive Rule.

[15] A summary of TERS was provided in Appendix B of our Peak Capacity consultation paper.

[16] Walton, R. Utility Dive, *Texas expands industrial demand response program as grid goes to the brink of rolling outages*, 15 July 2022.

3.24. The service first operated between November 2022 and March 2023. Prior to participation, providers were required to register with the system operator. Following registration, providers had to submit weekly forecasts and participate in testing.

3.25. NESO would signal an actual service requirement on a day-ahead basis, when its forecasts indicated there was likely to be insufficient supply to meet demand and maintain reserve margins. Procurement of the service could then occur on a day-ahead basis (with on-the-day procurement added for 2023-24), with providers required to submit DFS bids, and bids selected by NESO for activation in real-time the following day. Payment was provided for activations on a pay-as-bid basis.

3.26. The DFS was used for a second year over winter 2023-24. Over this period, the DFS was dispatched twice, delivering 3.7GWh of demand reduction, up to a peak of 400MW (almost 1% of peak demand), at a total cost, including testing, of £11.9 million[17] (around $27 million).

3.27. In 2024, DFS was amended to transition to an in-merit based margin tool, allowing demand-side flexibility to compete in economic dispatch processes year-round.

[17] National Grid Electricity System Operator, *Demand Flexibility Service Winter 2023-2024 – End of Year Report*, June 2024.

4. The case for an emergency reserve scheme in New Zealand

The problem: maintaining reliability of the power system for consumers

4.1. The primary problem we are seeking to address is the risk of 'uneconomic' involuntary load shedding. This can occur during infrequent emergency events where there may be inadequate supply to meet demand and maintain a secure and reliable power system. In these situations, the System Operator instructs EDBs to reduce demand (via involuntary load shedding) to maintain the supply-demand balance and prevent more wide-spread interruptions to power supplies.

What is uneconomic load shedding?

4.2. Uneconomic load shedding refers to a situation where consumers whose supply has been interrupted would have been willing to pay a price higher than the prevailing spot market price to avoid an outage.

4.3. By contrast, load shedding would be 'economic' if a consumer is unwilling to pay more than the cost of the additional action (ie, more supply, or reduced demand by other consumers) required to balance demand and supply and avoid an outage. The upper limit on the price consumers are notionally willing to pay to avoid an outage is known as VoLL.

An emergency reserve scheme can support security of supply during emergency events

4.4. Most of the time, the wholesale electricity market provides effective price signals for market participants to invest in, and operate, electricity generation to meet customer demand and manage risks such as planned and unplanned outages. However, it is difficult for the market to justify investing in system reliability to the point where the electricity system can ensure that generation will always meet demand.

4.5. This is particularly true for 'perfect storm' scenarios, where high demand coincides with low supply availability (eg, due to thermal plant outages and reduced wind generation), which can be very difficult for market participants to predict. In these rare events, load shedding currently operates as the last resort mechanism to maintain the supply-demand balance and the security of the power system.

4.6. The Authority wants to ensure that load shedding only occurs when absolutely necessary, given the impact that disconnection can have on consumers. The ERS, as proposed, would provide a 'penultimate resort' mechanism to use ahead of involuntary load shedding to support security of supply.

4.7. An ERS provides a means for consumers to pay for additional reliability in these infrequent events. Where that payment is less than the 'cost' of the alternative – an involuntary supply disruption – the ERS will contribute to an efficient electricity supply (ie, where it limits or prevent uneconomic load shedding).

Examples of recent events when an emergency reserve scheme could have helped

4.8. One example of this type of event was the low residual event on 9 August 2021, when unexpectedly low wind output coincided with an all-time high demand period because of a significant weather event, along with the loss of generation from a hydro plant. The System Operator directed EDBs to reduce load on their networks by around 1% to maintain the security of the power system. Actual load curtailment exceeded this level, although the Ministerial review of the event found that this load shedding did not need to happen.[18]

4.9. Another event arose on 10 May 2024 when an early cold snap coincided with low wind generation and planned outages at several power stations. The day before, the System Operator made a public call for voluntary load reductions to help maintain supply-demand balance. This voluntary call may have avoided the need for EDB load shedding, if the supply-demand imbalance had worsened. Transpower estimated that consumers reduced their consumption by around 240MW.[19]

How an emergency reserve scheme could have helped on 9 August 2021

The events of 9 August can be summarised as follows:[20]

1. At 6:40am, Transpower as System Operator notified market participants of the possibility of a shortage of supply that evening, if conditions were to worsen.
2. By 1pm, conditions had worsened, and the System Operator notified market participants that further generation offers were required to avoid the need for load shedding.
3. By 5pm, the situation had further worsened and a Grid Emergency Notice (GEN)[21] was issued, notifying market participants that there were insufficient offers to cover energy and reserves requirements.
4. At 6:47pm the System Operator instructed EDBs to reduce demand on their networks by 1%.
5. By 9:01pm the System Operator revised the GEN, advising all participants that they could restore all load, ending the grid emergency.

4.10. If an ERS had been available, the System Operator could have activated the ERS before step 4 in the sequence of events outlined above, as shown in Figure 1 below. This may have removed the need to instruct EDBs to reduce load or at least reduced the quantity of involuntary load reduction required.

4.11. It is important to note that the *Investigation into electricity supply interruptions of 9 August 2021*, found that load shedding did not need to occur due to the availability of underutilised demand-side resources (such as controllable load). We consider that an ERS can provide access to a firm amount of demand response resources to activate in events such as these, providing further certainty to the System Operator and reducing the likelihood of a repeat of 9 August.

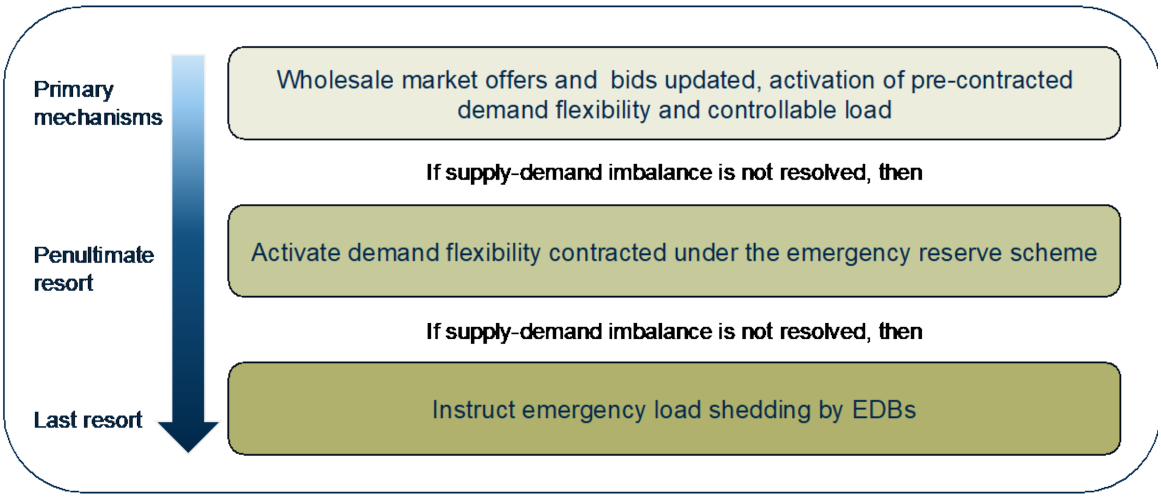
[18] Electricity Authority, 9 August 2021 demand management event review final report. We note that, in practice, load reduction attributed to this action was estimated to be ~3%. The Ministerial review found that load shedding need not have occurred. Both reviews identified improvements to be made to the System Operator's communications.
[19] Transpower, *Security of Supply Review – Winter 2024*, November 2024.
[20] Further details of the event are provided in the Authority's 9 August 2021 demand management event review final report and in the Ministerial investigation into electricity supply interruptions of 9 August 2021.
[21] A Grid Emergency Notice is issued after up to 1 hour ahead of real time when either a forecast supply deficit or a real-time deficit is seen after gate closure.

4.12. This event also highlights how relatively small quantities of demand or supply can be material in a grid emergency. The requested demand reduction of 1% equates to around 70-75MW at the time of peak demand.

Emergency reserves are part of a hierarchy of mechanisms to balance supply and demand

4.13. As shown in Figure 1, the Authority proposes the ERS should operate as a ‘penultimate resort’ mechanism. All primary, or ‘business as usual’, supply and demand-response mechanisms, including the use of controlled load by EDBs, should be deployed ahead of an ERS. An ERS will only be called on if these primary mechanisms are not expected to resolve the supply-demand imbalance. Involuntary load shedding will remain as the final resort to balance supply and demand and ensure the security of the power system.

Figure 1: Role of an emergency reserve scheme in the hierarchy of response to a potential supply-demand imbalance



Both the Authority and System Operator expect peak demand management to remain an issue over the coming years

4.14. As observed in recent years, greater generation intermittency is creating challenges for security of supply, especially during cold, still mornings and evenings. Slow-start thermal units are not operating as frequently as they used to. Growth in electricity demand and the decline in availability of thermal fuel and capacity are contributing to peak capacity risks. The system faces an ongoing challenge to coordinate a wide range of available resources as efficiently as possible for security of supply, to maximise benefits for consumers.

4.15. As the share of intermittent generation increases, so does the potential for an unforeseen mismatch in supply and demand, including due to inherent uncertainty in wind forecasts. Transpower’s 2025 SOSA identifies that winter capacity margins are sensitive to the availability of thermal generation units, including the timing of retirements. SOSA highlights increasing need for investment in peaking capacity, such as peaking generation, batteries and demand flexibility.

4.16. Transpower’s long-term forecasts consider when new supply projects are expected to be in operation. Continued investment in new supply sources will be required to maintain security of supply into the future; project delays pose a further risk to the supply-demand balance.

4.17. Moreover, Transpower's main forecasts do not consider the incidence of 'perfect storm' conditions. This means that even if adequate supply is in place reflecting longer-term forecasts, operational conditions and supply availability at a point in time may still require further measures, including load curtailment.

4.18. Transpower includes a 'constrained operational capacity' sensitivity in the SOSA, to consider the impacts of low thermal generation availability coinciding with low output from intermittent generation. In the 2025 SOSA, under these conditions, the North Island – Winter Capacity Margin is breached from 2026.

An emergency reserve scheme can also help unlock efficient demand flexibility

4.19. In addition to promoting a more secure and reliable supply, an ERS can also help unlock efficient demand flexibility. As discussed in our issues and options paper and noted in paragraph 2.12 above, industrial demand flexibility can be a lower cost alternative to additional supply when it is expected to be used infrequently.

4.20. An ERS provides an opportunity to reward demand response for its highest value use – to avoid involuntary uneconomic load shedding. This value provides the greatest opportunity to offer incentives for demand flexibility, noting that insufficient incentives are one of the main barriers identified to greater use of demand flexibility in the electricity market.

Previous consideration of an emergency reserve scheme for New Zealand

4.21. Over the past few years, 'ERS-like' mechanisms have been considered by a range of parties, including the Authority.

4.22. Over the period 2022 to 2023, the Authority considered similar schemes in its 'Option K' in the Driving efficient solutions to promote consumer interests through Winter 2023 (Winter 2023) workstream; CEO Forum proposal for a standby ancillary service;[22] and interim options in the Potential solutions for peak electricity capacity issues (Peak Capacity) workstream.

4.23. The Authority decided not to take forward any of these options at that point because we considered they would:

(a) not guarantee that only resources that were additional to the business-as-usual scenario were rewarded (lack of additionality)

(b) be unlikely to be effective at providing additional resilience in the short term to manage peak capacity issues

(c) be a significant departure from the current market design

(d) carry several risks – including potentially chilling investment signals and undermining confidence in the market

(e) have the potential to be high cost.

[22] The CEO Forum (a working group of the CEOs of the six larger generators, four largest distributors, and Transpower), put forward a proposed out-of-market mechanism payment for resources that would be ring-fenced form other market mechanisms. More information is available in this submission to the Authority.

MDAG made a contingent recommendation to consider an emergency reserve scheme

4.24. In late 2023, MDAG recommended a market-led approach to demand-side flexibility, arguing that competition would unlock the most efficient forms of demand response. However, it did make a contingent recommendation to develop a 'last resort' demand-side flexibility scheme (recommendation 30).[23] This was conceptualised as being like Australia's RERT scheme.

4.25. This recommendation was contingent on the Authority not being satisfied the market was procuring enough demand response to manage security of supply.

A well-designed emergency reserve scheme will minimise risks and could offer benefits to the New Zealand electricity market

4.26. The work (discussed in Section 2) that the Authority and the System Operator have underway is important for promoting the reliability of the electricity system over time, including during periods of tight supply. However, the risk remains that we will experience unexpected coincident events of high demand and limited supply into the future, as occurred in May 2024.

4.27. Our issues and options paper highlighted the potential for demand flexibility to play a role in supporting system reliability during periods of tight supply. We consider that an ERS, if designed effectively, could enable access to demand flexibility that would otherwise be inaccessible to the market during periods of tight supply.

How an emergency reserve scheme can deliver benefit

4.28. To assess how an ERS can deliver overall benefit to New Zealand electricity consumers, we have considered the design of an ERS in the context of the guiding principles we proposed in the issues and options paper (included in Appendix B of this ERS consultation paper).

4.29. As noted previously, many submissions on the issues and options paper indicated support for the proposal to establish an ERS. Of those that commented on the benefits of the scheme, submitters agreed that such a scheme could support the reliability of power supplies, and the Electrical Engineers Association (EEA) submission noted it could help build the capability of demand-side providers.

4.30. These principles, which align with our main statutory objective and the Government Policy Statement on Electricity, seek to achieve the following outcomes:

(a) enable diversity of parties competing to bring solutions that meet customer demand

(b) ensure the secure and reliable supply of electricity

(c) enable efficient operation of the electricity industry and minimise long-term costs for consumers

(d) minimise cost, complexity and effort of participation for demand response providers

[23] MDAG, *Price discovery in a renewables-based electricity system – final recommendations paper*, 11 December 2023.

(e) maximise strategic alignment with the broader Task Force and Authority work programme.

4.31. To meet these principles, the ERS design needs to address the risks identified by the Authority in considering earlier schemes (summarised in paragraph 4.30 above).

Does an emergency reserve scheme create a moral hazard?

4.32. In addition to reflecting on the risks previously identified with similar schemes, the Authority has considered if an ERS might create a ‘moral hazard’. Moral hazard refers to a party becoming more inclined to take a particular risk because they believe another party (ie, an insurer) will cover the costs of any damage.

4.33. An ERS could create a moral hazard by leading to sub-optimal investment or operational decisions because market participants are ‘insured’ against the risk of a supply shortfall and no longer consider this a risk they need to manage.

4.34. We consider that this is a residual risk. However, we consider the risk can be substantially mitigated by elements of the scheme design.

The design of an emergency reserve scheme can ensure the benefits are realised and the risks are managed

4.35. To meet these guiding principles and address the identified risks, including creating a moral hazard, we consider that an ERS must be designed to:

(a) **Require ‘additionality’**, by enabling participation from those who currently have insufficient incentives to participate in other market or contractual mechanisms, and who have the technical capability to be relied upon by the System Operator to respond. This means excluding participation by those for which other mechanisms are more appropriate (eg, excluding generation, DD and dispatch notification (DNL) participants), or price sensitive load that would otherwise be used in the absence of an ERS.

(b) Not affect the operation of existing market, contractual and other mechanisms, or long-term investment signals to maintain supply-demand balance by:

(i) **operating as late as possible**, after all other market and demand flexibility mechanisms, as a penultimate action ahead of involuntary load shedding

(ii) **being used infrequently**, only in situations that are very difficult to forecast

(iii) **ensuring scarcity price signals** still take effect when the scheme is activated, to maintain short-term operational and long-term investment signals

(iv) **using existing processes for planning for, and managing, grid emergencies,** which will ensure the scheme complements existing wholesale market and grid emergency mechanisms and should also minimise implementation and administration costs.

(c) **Facilitate risk management,** allocating costs in a manner which ensures the participants best placed to manage risks of ERS use are incentivised to do so.

(d) **Be relatively low cost to implement and operate**, whilst ensuring ERS providers have the necessary capability, including by:

(i) **capping ERS costs at VoLL** to ensure ERS is only used where it is lower cost than the maximum consumers are willing to pay to avoid an outage

(ii) **avoiding unnecessary technical requirements,** which could deter participation and increase costs

(iii) **leveraging existing market processes with minimal change,** minimising the need for changes to complex existing market scheduling and dispatch processes, but leveraging existing processes where practical such as for settling ancillary services costs.

4.36. We note that several submissions to our issues and options paper identified one or more of these considerations. In particular, submitters highlighted the need to ensure that an ERS, if implemented, provides additionality and does not distort the operation of other market or contractual arrangements. Submitters, such as Transpower and EEA, also sought to ensure the scheme did not introduce unnecessary complexity and cost in the way it is implemented.

4.37. Several submissions also sought more information on how an ERS would integrate into existing system and processes, including for market scheduling, dispatch and pricing, and emergency management.

4.38. Section 5 below outlines our proposed high-level design for an ERS, having regard to the considerations outlined in the above paragraphs. Section 6 then provides an assessment of the proposed design against the guiding principles and Section 7 outlines the early implementation considerations and providers further discussion on VoLL and system security standards, which are important parameters in the context of an ERS.

Questions

Q1. Do you agree with our rationale for establishing an ERS? Why/why not?

Q2. Are there other factors or risks you consider relevant to our decision to implement an ERS?

5. Proposed emergency reserve scheme design

5.1. This section sets out the Authority's proposed high-level design for an ERS in the New Zealand market. We seek your feedback on these design elements.

5.2. To support this design work, the Authority commissioned RBP to consider several options and recommend a package of design elements. RBP's *Evaluation of an Emergency Reserve Scheme* report is provided in Appendix A. The report provides a qualitative evaluation of design options against criteria which are broadly aligned with the proposed guiding principles from our industrial flexibility roadmap, as summarised in paragraph 4.30.

5.3. The design elements set out in this paper incorporate RBP's recommendations. We have also considered the risks and challenges discussed in Section 4 above and the mechanisms in place in other jurisdictions discussed in Section 3, to inform our proposed design. Where the Authority has departed from RBP's recommendations, we have set out our reasons for doing so, with reference to the guiding principles.

Proposed objectives for the emergency reserve scheme

5.4. Any ERS scheme put in place needs to promote reliability and efficiency in line with our main statutory objective – without distorting investment incentives or impeding competition in the wider market.

5.5. As noted by RBP in its Demand Response Programmes – International Scan for the Authority, and by submitters to our issues and options paper, it is important to have a clear purpose for an ERS.

5.6. We seek your views on two proposed objectives for the proposed scheme:

(a) **Primary objective: promote system security and reliability** and minimise the likelihood and extent of uneconomic load shedding during infrequent periods when demand is high and insufficient supply is available from other sources.

(b) **Secondary objective: build consumer capability to provide demand flexibility** more generally, through organisational capability building and investments in equipment.

An emergency reserve scheme is not intended to preclude participation by flexibility services in other mechanisms

5.7. This proposal to establish an ERS is not intended to preclude flexibility services – from batteries, distributed generation, controllable load or other forms of demand response – from participating either directly in the market or via a contract with a retailer or EDB.[24]

5.8. These primary mechanisms can enable parties to manage their exposure to high spot market prices and represent a more substantial and ongoing opportunity than an ERS, which is intended to be activated infrequently and for short periods of time. As noted above and discussed further in paragraph 5.32 below, a key requirement

[24] While we would expect commercial arrangements to be negotiated directly between parties, facilitation measures should provide additional support (eg, the new super peak and proposed demand flexibility standardised product).

of an ERS is that it provides additionality to these primary mechanisms, minimising the risk of parties ‘double dipping’ or withdrawing capacity provided through market and contractual mechanisms.

Overview of proposed emergency reserve scheme

The proposed emergency reserve scheme would have a specific role and needs to be considered in the context of the evolving role for demand flexibility

5.9. The Authority proposes that an ERS will play a very specific and narrowly defined role, to meet a defined system need – namely to reduce or avoid uneconomic involuntary load shedding during infrequent emergency events.

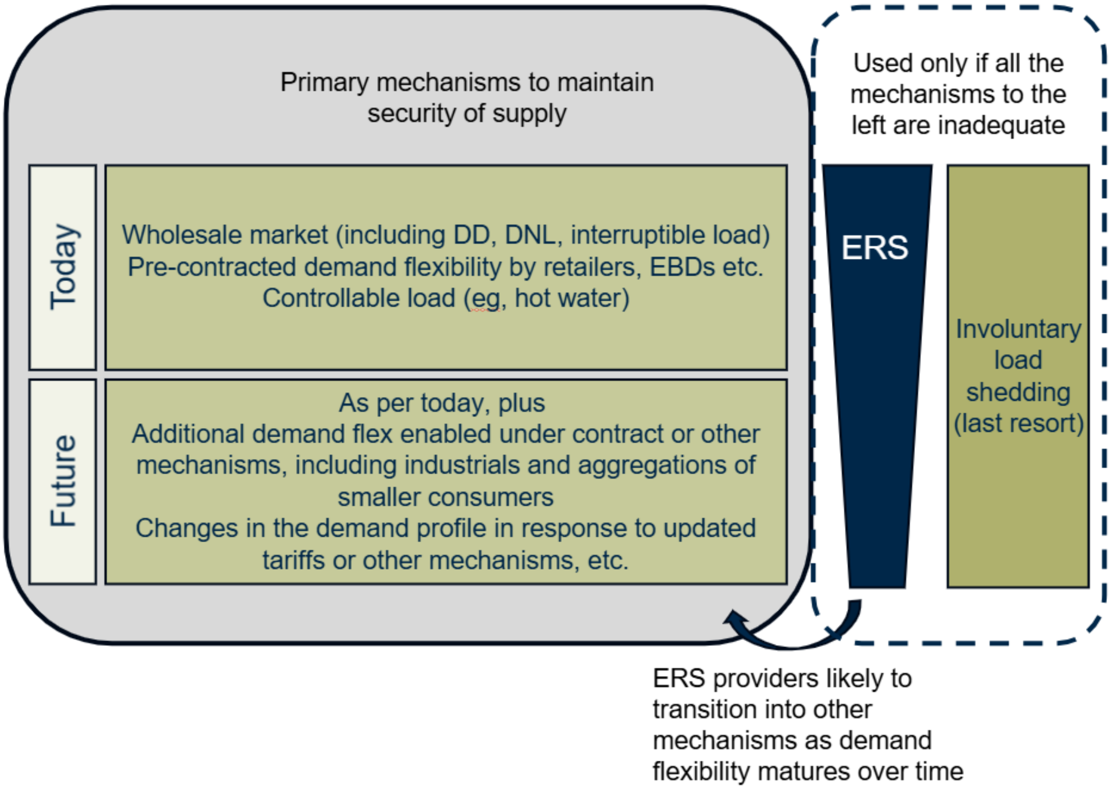
5.10. As discussed in Section 4 above, to maximise competition, reliability and efficiency of the market overall, the ERS should not displace the operation of other market or contractual mechanisms designed to help balance supply and demand.

5.11. The ERS is intended to be a ‘penultimate resort’ mechanism, providing access to capacity that is not otherwise available in the wholesale electricity market or via other mechanisms (eg, contracts, controllable load). It is intended to be procured only when the System Operator identifies a potential shortfall, and activated infrequently in emergency events to reduce or avoid uneconomic involuntary load shedding.

5.12. As demand flexibility matures in our electricity system, including because of initiatives proposed in our issues and options paper and the development of new and emerging technologies, the Authority anticipates that additional demand flexibility will be available for use ahead of targeted mechanisms like an ERS or involuntary load shedding. We also anticipate that some initial ERS providers may transition to other demand flexibility mechanisms as these mature. An ERS may represent a high value use of demand flexibility. However, given it is intended to be used infrequently, other demand flexibility mechanisms are expected to offer greater overall benefit to many potential providers.

5.13. Figure 2 summarises both the specific role proposed for an ERS and how this is anticipated to evolve over time as demand flexibility matures in the market.

Figure 2: Role of an emergency reserve scheme as demand flexibility evolves



Interaction of the ERS with last resort load reduction mechanisms

5.14. As proposed, the ERS would operate as a ‘penultimate resort’ mechanism ahead of involuntary load shedding. An ERS is intended to reduce the likelihood or extent of involuntary load shedding but cannot remove the possibility entirely.

5.15. There are two different types of involuntary load shedding: manual load shedding and automatic under-frequency load shedding (AUFLS).

5.16. Manual load shedding involves the System Operator instructing EDBs to reduce load on their networks by a specified amount, such as what occurred on 9 August 2021.

5.17. If, in an emergency event, emergency reserves are not sufficient to completely avoid load shedding, some level of manual load shedding may still be required. In this situation, EDBs need to be informed of any activated ERS by providers connected to their networks, to ensure that any instructed load shedding results in an additional load reduction (ie, the ERS providers’ reductions are not ‘double counted’).

5.18. AUFLS is an automatic mechanism which disconnects load if system frequency falls too low and cannot be rectified using normal market tools such as instantaneous reserves. This is an essential protection mechanism to prevent more widespread outages. AUFLS, while rarely used, is most likely to be required following a series of unexpected contingency events on the power system, such as the coincident tripping of several generation systems or major transmission infrastructure.

5.19. AUFLS operates automatically and will reduce load in pre-determined ‘blocks’ until system frequency is stabilised. AUFLS is a discrete mechanism. AUFLS blocks are used only for an under-frequency event and are not used for manual load shedding.

As a result, there is no direct interaction between the proposed ERS and AUFLS operation.

5.20. In fulfilling their AUFLS obligation under the Code, distributors and direct-connect industrial consumers, must ensure that they have at least 32% of their pre-event load armed for AUFLS at all times[25]. This proportion would need to be maintained following the activation of any ERS demand response. Potential providers would need to consider how they maintain their AUFLS obligation when deciding how to configure their ERS demand response.[26]

5.21. OCCs are another form of last resort demand response mechanism. The System Operator may declare an OCC when there is a risk of an electricity shortage that exceeds 10%, and the shortage is forecast to continue for more than a week. OCCs and an ERS are both tools that the System Operator can consider, depending on the specific circumstances of an emergency event.

5.22. While it is possible that the ERS may be activated during an OCC, the two mechanisms have different roles. The ERS is intended to help manage a potential supply shortfall identified relatively close to real-time and is not intended to be used for an extended duration.

5.23. During an OCC, retailers are required to compensate consumers for reducing demand. Customer payments for OCCs encourage consumers to conserve energy, avoid distorting incentives for prudent risk management by retailers, and incentivise investment by generators in last-resort dry-year generation (to fulfil their hedge obligations). The rationale for customer payments for OCCs has some conceptual parallels with the proposed ERS payments.

Key phases of an emergency reserve scheme

5.24. The proposed ERS can be described as a process with **five key phases**, supported by ongoing information sharing and monitoring. There are activities required to:

(a) **prepare** for procurement and use of emergency reserves, including planning and monitoring of the supply-demand outlook

(b) **procure** emergency reserves when a need is identified

(c) **ensure** providers can deliver the services when required, by providing pre-activation information

(d) **activate** the service in operational timeframes and manage interactions with the wholesale electricity market and grid emergency procedures

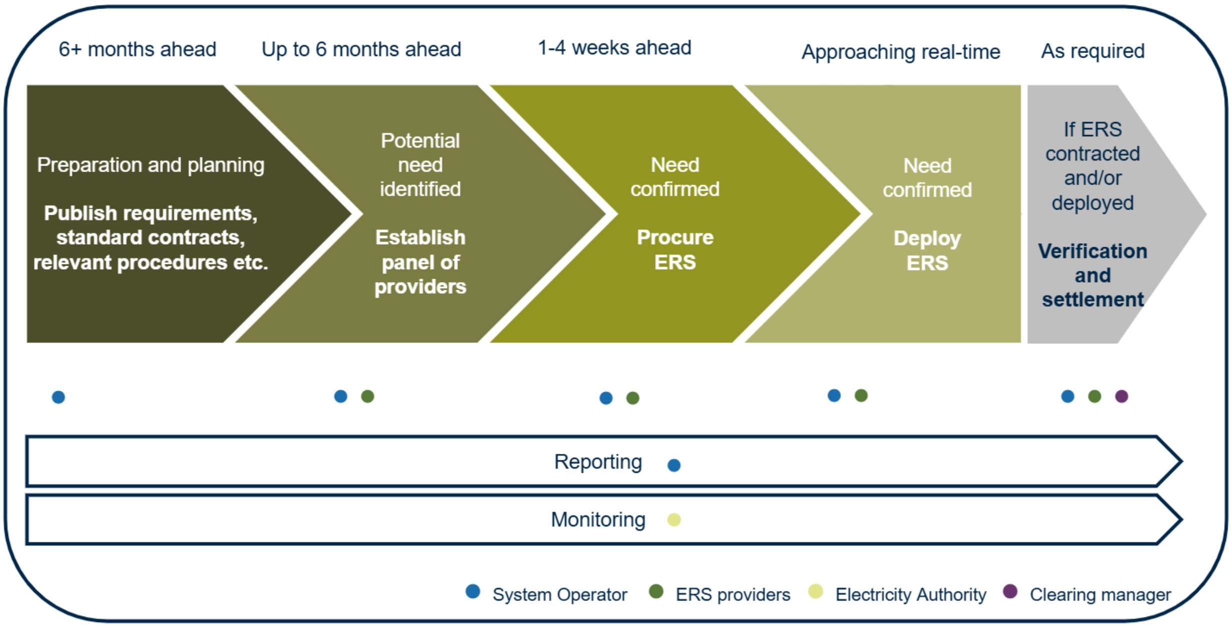
(e) **verify** performance and settle ERS costs.

5.25. These phases, including their indicative timeframes and the parties involved, are summarised in Figure 3. The sections following this outline the Authority's proposed high-level design of the ERS.

[25] See Schedule 8.3, Technical Code B – Emergencies, clause 7 of the Code.

[26] This is consistent with the current approach for providers of interruptible load. In its submission to the issues and options paper, NZ Steel considered this requirement a barrier to the provision of interruptible load.

Figure 3: Overview of the key phases of an emergency reserve scheme



Proposed emergency reserve scheme design features

Key design elements

5.26. At a high-level, the proposed ERS is comprised of **six key design elements**:

(a) **eligibility to participate**: who can provide the service and the requirements they need to meet

(b) **procurement**: when and how ERS is procured

(c) **activation**: when and how the service is activated (including pre-activation activities) and how this interacts with existing spot market processes

(d) **pricing and settlement**: the prices providers may charge for the service, how the service is paid for and costs are allocated

(e) **performance management**: how the risk of non-performance is minimised and any non-performance is managed

(f) **information provision and publication**: the information to be provided to support the effective operation and monitoring of the scheme.

5.27. The proposed ERS design seeks to use existing processes (eg, planning, communication and payments) where appropriate, to reduce the costs of administering the ERS and ensure it complements existing market operations.

5.28. We consider that the ERS could be implemented in a similar manner to the other ancillary services currently procured by the System Operator. The implementation of the scheme would take a mixture of Code changes, changes to system operation documents (eg, policy statement and the ancillary services procurement plan), and the contractual arrangements between the System Operator and providers.

5.29. The following sections outline our proposals for each of these design elements, including the rationale for any differences from RBP's recommendations.

Eligibility to participate

All demand flexibility providers should be eligible to participate

5.30. The Authority proposes that any source of demand flexibility should be eligible to provide ERS, provided it can meet the relevant service requirements and would not already have been contracted or otherwise used before an ERS is activated. The scope of participation includes demand flexibility provided by industrials as well as aggregations of smaller commercial and residential consumers.

5.31. While this will mean that a range of demand flexibility sources can participate, we need to moderate this to ensure that the ERS doesn't remove demand flexibility that would otherwise participate in the absence of the scheme. A scenario where large amounts of existing demand flexibility move into the ERS scheme may increase the frequency of scarcity pricing events, undermining reliability and efficiency outcomes.

5.32. Additionality is a key consideration in the design of the scheme, to ensure the ERS does not result in consumers paying for services that would already be provided, or for capacity that should be supplied in the competitive market.

5.33. Therefore, the Authority proposes that the following demand flexibility would be ineligible to provide ERS:

(a) demand flexibility that is offered into DD, DNL, or instantaneous reserves

(b) demand flexibility that is provided under contractual agreements with retailers or EDBs

(c) any other demand flexibility which would be activated prior to or in response to a grid emergency (eg, controllable load resources that can be activated by EDBs, such as hot water loads).

Aggregated demand flexibility from small consumers should be eligible to participate

5.34. We propose that aggregations of smaller consumers should be able to participate, provided they can meet the service specifications such as performance and measurement requirements.

5.35. There are additional complexities in managing aggregations of small consumers, including coordination and communication of resources and determination of baseline consumption across multiple sites with potentially volatile consumption patterns. RBP noted these considerations in relation to aggregations of residential consumers, and that these consumers may offer some, but not much, additionality.[27] However, RBP recommends that no consumer types should be excluded from participation. The inclusion of residential aggregations would enhance competition within the scheme and, overall, their inclusion, is expected to provide a net benefit.

5.36. The Authority considers that, if aggregators can manage these factors and meet relevant service requirements, residential and other small consumers should not be excluded from participation. Further, including them may increase the pool of

[27] On the basis that the ERS alone may not provide sufficient incentive for aggregations of residential consumers, and if they are established, it is likely the case that they are already providing demand response at peak times. Refer to page 29 of the RBP report in Appendix A.

potential providers, enhancing competitive outcomes within the scheme and the extent to which the scheme contributes to security of supply.

5.37. There is evidence that smaller consumer aggregations can provide a service akin to an ERS. The coordination capability of aggregated resources (residential solar batteries) to help manage peak demand events in the New Zealand system was successfully tested in the 2023 Winter Peak Innovation Pilot. In other jurisdictions, including Australia and the United Kingdom, aggregations of smaller consumers, including residential consumers, have successfully provided similar services.

Generation and batteries should be excluded from participation

5.38. The Authority proposes that generation and batteries should not be eligible to participate in the ERS.

Excluding market generation

5.39. The Authority proposes that market generation and batteries be excluded from the scheme. RBP also recommended this approach.

5.40. Inclusion of market generation would be contrary to the intent of the scheme. Leading into the activation of an ERS during a period of tight supply, we would expect generators to offer as much generation as possible at that given period. This is reflected in the System Operator's existing powers under a grid emergency to enable generators to update offers within gate closure to ensure that generators are providing as much supply as possible during these periods.

5.41. Grid scale batteries will play an important role in helping the electricity system to manage peak periods. These units can already earn revenue when they are discharging in the spot market – unlike other forms of demand-side flexibility. We therefore consider that these units already have sufficient incentive to operate before an ERS is activated.

5.42. Including market generation would likely have adverse impacts on competition and efficiency in the wider market and potentially incentivise the withdrawal of capacity from the wholesale market.

Excluding off-market generation and batteries

5.43. The Authority proposes that off-market generation and batteries[28] should also be excluded from the scheme, which differs from RBP's recommendations.

5.44. RBP considered that off-market generation should be included in the scheme to maximise participation and hence competition among potential providers. We acknowledge the potential competition benefits, which could ultimately lower the cost of the scheme.

5.45. Our preliminary view is that during the most likely circumstances where an ERS may be activated, network demand would be very high and off-market generation (such as diesel gensets), and any network-connected batteries are likely to already be used to manage local network congestion or support any outages on the network. We consider that these types of resources are likely to already being used ahead of any activation of the ERS and therefore may not offer additionality and

[28] This is not intended to include on-site battery storage systems used to enable demand flexibility, as discussed in paragraph 5.48 below.

may increase overall costs for consumers. We welcome any data or information from participants on this view.

5.46. When considered against the proposed guiding principles, if off-market generation and batteries are not likely to provide any additionality, the Authority considers that limiting participation to demand-side flexibility results in better outcomes for efficiency and competition in the market more broadly, without materially reducing competition within the scheme.

5.47. We welcome feedback on this approach, in particular whether stakeholders believe there is off-market generation or batteries that may not be activated in an emergency event outside of an ERS. We acknowledge that several submissions to the issues and options paper considered that flexibility from sources other than industrial demand should be considered by the Authority for the proposed ERS.[29]

5.48. It should be noted that this proposal is not intended to preclude demand flexibility that is enabled by on-site generation or batteries. The Authority is agnostic as to how the demand flexibility is enabled, provided it results in the ability to reduce demand supplied by the grid during relevant time periods.

The System Operator should determine the service requirements

5.49. The Authority supports RBP's recommendation that the service requirements should be determined by the System Operator. This includes:

(a) the service specification

(b) eligibility criteria, including to ensure additionality

(c) technical requirements, including measurement and verification requirements

(d) the methodology for determining the baseline demand from which to measure demand response provided under the scheme.

5.50. Some of the considerations in determining the baseline methodology are discussed in section 2.9.2 of RBP's report in Appendix A.

5.51. Like the existing ancillary services, we consider that these criteria best sit with the ancillary services procurement plan rather than the Code. As the procurement plan would be a System Operator document that is incorporated into the Code, this gives flexibility to the System Operator as to the exact technical requirements and how it will implement the scheme with providers.

Procurement

The System Operator should procure the service via a competitive tender process

5.52. We propose that procurement of the ERS should occur by way of a competitive tender process run by the System Operator. A competitive tender process provides an effective means of ensuring efficient market outcomes by:

(a) ensuring proposals face the discipline of competition

[29] See the submissions from Counties Energy, Meridian Energy, Powerco, and Vector. Vector noted on page 10 of its submission that it was 'aware of tens of MW, if not over 100 MW of standby backup generation connected to our network alone'.

(b) providing for flexibility of terms to maximise participation

(c) being relatively simple and low-cost to administer, not requiring the development of new or amended market systems. [30]

5.53. The tender process should seek to procure sufficient ERS (if available) to meet the identified shortfall (discussed in the next section). This would likely be on a firm quantity procurement basis (ie, where the System Operator procures services on a fixed quantity or fixed price basis). This occurs whether the ancillary service is dispatched or not (eg, black start).[31] We think that this would likely be the most appropriate form of procurement for this type of product, compared to a half-hour clearing market process – the other form of procurement that is undertaken for instantaneous reserves and frequency keeping.

Procurement timing needs to balance participation with forecast accuracy

5.54. A critical design factor for the ERS is determining when procurement should occur. Procuring earlier is likely to increase the pool of potential providers but forecast accuracy for shortfall quantities and locations improves closer to the relevant trading period.

5.55. The Authority supports RBP's recommendation to procure within four weeks of an identified shortfall. RBP found that long-notice procurement (eg, 3 to 12 months ahead) adds limited value, as forecasts this far ahead are unlikely to represent real, or near real-time, risks. For example, neither the 2020 nor 2023 SOSAs identified a shortfall for the following winter period. Similarly, RBP found that medium-notice procurement (1 to 3 months ahead) offers little improvement in risk accuracy.

5.56. The main challenge with short-notice procurement is attracting enough providers. To address this, the Authority proposes the System Operator should establish a pre-qualified panel of providers (as recommended by RBP). This would allow contract terms and service specifications to be agreed, and due diligence to be undertaken, in advance, streamlining the subsequent process when a shortfall is identified.

The procurement trigger should leverage existing planning processes

Existing security of supply forecasting can be leveraged for procurement

5.57. A key component of the System Operator's role is forecasting and assessing risks, including whether there is adequate supply to meet demand on a forward-looking basis. There are three relevant security of supply monitoring mechanisms for ERS design:

(a) Two of these mechanisms are relevant for ERS procurement:

(i) the energy and capacity margins used in the SOSA, which contains the long-term forecasts; and

[30] Meridian Energy's submission considered that, if introduced, procurement of ERS should occur via a market-based mechanisms such as a tender.
[31] Subject to the payment structure agreed. Payments for ERS are discussed at paragraph 5.79 below.

(ii) the New Zealand Generation Balance (NZGB), which forecasts whether there is adequate capacity to meet forecast demand for the next 200 days.

(b) The third mechanism, the forecast residuals from market schedules, are relevant to the activation of the ERS (discussed further at paragraph 5.67).

5.58. The RBP report sets out more information on these mechanisms.[32]

5.59. Given the proposed short-notice procurement approach, the long-term forecasts in the SOSA are not suitable as direct triggers for ERS procurement. However, these forecasts still provide valuable early signs of the likelihood of ERS procurement. The SOSA could also support the System Operator's market testing and pre-procurement activities, such as identifying the need to form a panel of pre-qualified providers.

5.60. The Authority supports RBP's recommendation that the trigger for procurement should occur when the N-1 balance falls below zero in the NZGB. The System Operator should identify both the likely quantities and locations of ERS required.

Some modifications to the New Zealand Generation Balance could assist with procurement of emergency reserves

5.61. A further consideration is whether any adjustment should be made to the NZGB to account not only for uncertainty in wind generation due to variations in weather conditions (as already occurs), but also the *uncertainty in wind generation forecasts* ('forecast uncertainty'), which could be a significant contributor to the 'perfect storm' conditions which give rise to the need for emergency reserves.[33]

5.62. While RBP discussed an option for such an adjustment, the Authority considers this to be a matter for the System Operator to consider.

Activation

5.63. Activation of the ERS is intended to reflect the operational hierarchy outlined in Figure 1 above, whereby the ERS is intended to be used after all other market and contractual mechanisms, including EDB controllable load resources, have been used and a forecast supply-demand imbalance remains.[34]

A 'pre-activation' process can facilitate activation decisions closer to real time and support provider performance

5.64. Pre-activation refers to preparatory activities, including communications, that occur in the lead up to an activation event, to ensure providers can deliver the service as intended. Activation then refers to the actual use of the service, which is triggered by a notification from the System Operator to the provider.

5.65. Pre-activation activities are proposed to occur between 1 to 36 hours ahead, depending on the circumstances. This is to enable providers to prepare their processes to provide the service, which might include switching power supply to another source or planning to ramp down operational activities.

[32] Refer to section 2.3 of RBP's report in Appendix A.
[33] In 2024, Transpower as System Operator adjusted the supply scenarios used the NZGB to include a scenario which captures the risk of low wind by including 20% of wind capacity.
[34] Transpower's submission to the issues and options paper noted the need for a clear operational hierarchy.

5.66. It is then proposed that activation is triggered with up to an hour's notice, ideally after gate closure in the spot market for the relevant time period to ensure all market resources are dispatched ahead of ERS.

Pre-activation and activation should be triggered by forecast residuals in the System Operator's operational forecasts, but managed outside of market systems

5.67. In line with RBP's recommendations, the Authority proposes that:

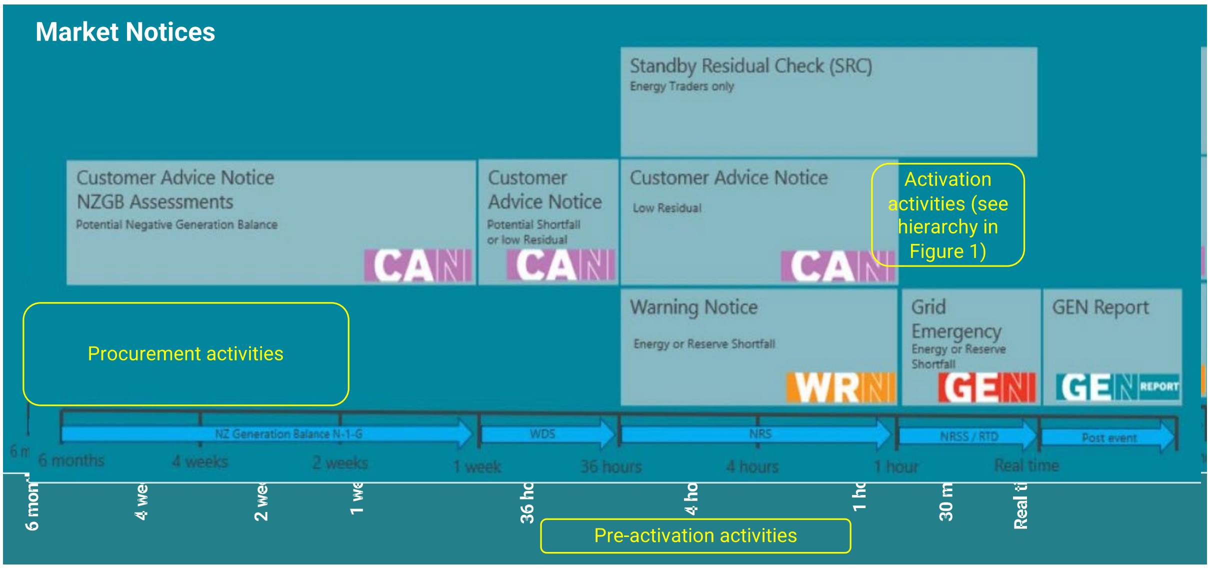
(a) pre-activation should occur if the residuals determined in the Non-Response Schedule are less than zero

(b) activation should be triggered if the Non-Response Schedule Short (NRSS) residuals are less than zero[35]

(c) as discussed above for the NZGB, the Authority also considers these forecasts should be updated to account for forecast uncertainty.

5.68. The procurement and activation triggers should be integrated into the System Operator's existing forecast and communications processes for managing capacity shortfalls. This is summarised in Figure 4, which has been adapted from the System Operator's [Notices for insufficient generation](#).

Figure 4: Summary of proposed emergency procurement and activation timing



5.69. Integrating ERS planning and activation triggers with existing System Operator planning processes is likely to be more efficient than creating bespoke processes. While some modification to these processes is recommended to account for forecast uncertainty, we note that the System Operator continually evolves its operational planning and forecasting as new input information becomes available or new power system conditions are expected.[36]

5.70. By contrast, it is likely that modifying market clearing and dispatch processes would be more complex and higher cost than needed, particularly considering the

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[35] RBP providers further information on residuals forecasts, see page 35 of the report in Appendix A.

[36] The proposed evolution is aligned with the changes in the power system to more intermittent renewable generation explored by Transpower in its recent its *Evolving market resource co-ordination in Aotearoa New Zealand White Paper*, available at https://www.transpower.co.nz/evolving-market-resource-co-ordination-aotearoa-new-zealand-closed.

expected infrequent use of the scheme. The Authority does not consider it would be efficient to integrate ERS activation into these market processes.[37]

5.71. The Authority notes that the accuracy of the load and generation forecasts that make up the Non-Response Schedule is important in ensuring that the operation of the ERS contributes to reliability and is efficient. Some recent improvements to forecasting are discussed in Section 2 above.

Activation of emergency reserves should not dilute the signals provided by scarcity pricing

5.72. Ordinarily, when demand decreases in real-time, spot market prices adjust to the level of the marginal price of the last supply source dispatched to meet demand. We would anticipate spot market prices to be at scarcity pricing levels when the ERS is activated. Activating the ERS would reduce demand, which could have the result of reducing prices to below scarcity pricing levels as there may no longer be insufficient supply from the market (depending on the circumstances of the event).

5.73. The Authority supports RBP's recommendation that any demand reduced because of the activation of ERS be 'added back' into nodal load schedules so that spot prices are set at the level they would have been (likely scarcity prices) in the absence of the scheme.

5.74. This is to avoid distorting the operation of the wholesale electricity market – by ensuring that prices continue to effectively signal the need for both supply in real-time and investment in additional supply – and ensure the ERS delivers overall efficiency benefits to consumers.

5.75. This is akin to the approach currently taken when EDBs are instructed to curtail load in their local network, where the Real-Time Dispatch Pricing Schedule is adjusted to add back the instructed load shedding at relevant nodes, restoring prices to higher levels.

Restoration and coordination with distributors

5.76. The Authority notes that the restoration of load that has responded to an ERS activation will also need to be managed by the System Operator. For any providers that are connected to a distribution network, some level of coordination between the System Operator, ERS provider and EDBs will be required to avoid any adverse impacts from sudden changes in load on networks (both through ERS activation and restoration). This issue was noted by several EDBs, the EEA, and Energy Networks Aotearoa (ENA) in their submissions to the issues and options paper. This issue was not considered in RBP's report in Appendix A.

5.77. The Authority's preliminary view is that the following requirements would enable this, and welcomes feedback from stakeholders on this area:

(a) The EDBs are advised of any providers connected to their network and the quantum of response. This could be done by either the System Operator or the provider.

[37] We note that Transpower's submission to the issues and options paper suggested integrating into the existing DD mechanism may be a practical solution. The Authority will engage further with the System Operator on options for implementing the ERS, if progressed. Section 7 discusses implementation considerations.

(b) Coordination between the System Operator and relevant EBDs in relation to any involuntary load shedding that may be required in an emergency after ERS has been exhausted, and in the restoration of loads once the emergency has passed.

5.78. The Authority notes that submissions from EDBs and the ENA also recommended the application of a common load management protocol, being developed by the ENA's Future Network Forum, as being relevant to an ERS.[38] The Authority does not consider this to be within the scope of an ERS design at this stage, but notes there is a linkage between these areas of work to consider during the design of ERS service provider contracts.

Pricing and settlement

Flexibility in pricing structures can enhance participation, but to be efficient, costs must not exceed the value of lost load

5.79. The Authority proposes that pricing be determined for each provider as part of their contract with the System Operator, and that providers can structure their pricing to best meet their own cost structures, which may include:

(a) preparation costs, such as costs incurred in installing equipment, implementing processes and training staff to be able to provide ERS

(b) availability costs, to be ready to provide the service within the notification timelines

(c) pre-activation costs, including costs to prepare to reduce demand or transition to an alternative energy source

(d) activation costs, relating to the costs of providing the service, including foregone production and the costs of alternative energy sources, if applicable.

5.80. The cost structure for each provider can differ and is to be determined in the contract between the provider with the System Operator. While the System Operator is expected to specify minimum requirements in its service specification for the ERS, the contract between the provider and the System Operator should also enable a reasonable level of flexibility on matters that may differ between providers and are relevant to determining the appropriate costs (eg, minimum or maximum duration of the service, maximum number or frequency of activations, and ramp rates).[39]

5.81. For clarity, the Authority proposes that providers be able to structure their offers to reflect their individual costs, payments will occur across two time horizons: availability costs (including preparation costs) and activation costs (including pre-activation costs). Proposed payment periods are outlined at Section 5.91 below.

5.82. In its submission to the issues and options paper, Vector indicated support for a payment structure that includes availability payments and was cost-based. WEL

[38] See submissions to the issues and options paper from Counties Energy, the ENA, Orion, Unison and Centralines and Vector.

[39] Pages 10 – 11 of Enel X's submission identified several elements of the service definition. These detailed design elements will be considered in subsequent consultations if the Authority decides to proceed with the implementation of an ERS.

Networks also supported availability and activation payments, based on the provider's offer prices.

The System Operator should use reasonable efforts to ensure the cost of the scheme is less than the value of lost load

5.83. While the competitive tender process will encourage efficient pricing by providers, the Authority also proposes that the System Operator should make reasonable endeavours to ensure that, *at the time of procurement*, the forecast unit cost of ERS provision is not greater than VoLL.[40]

5.84. VoLL is the value of unserved energy and is sometimes referred to as the value of customer reliability. It represents the economic value a consumer places on electricity they would have used but didn't receive due to a power outage. Capping costs at VoLL ensures that the ERS provides a benefit overall to consumers.[41]

5.85. As noted by RBP, a 'reasonable endeavours' requirement for the System Operator to ensure costs less than VoLL is appropriate for an ERS. The alternative is a strict obligation to select the least cost combination of compliant providers. Ideally, the System Operator will select the lowest cost combination of offers. However, the terms of each offer are likely to be unique, as are the circumstances of each potential event. A strict obligation would be a difficult requirement to satisfy in this context, and it is reasonable for the System Operator to consider factors such as response time, load patterns and the risk of resource fatigue in evaluating offers.

RBP considered alternative prices and further evaluation requirements for the System Operator

5.86. The proposals outlined above are consistent with RBP's recommendations. RBP also considered limiting the allowable costs to activation and availability, or activation only, and found that these options would likely reduce the pool of potential providers. This could have detrimental impacts on competition in providing the service and the efficiency of the service, as well as on the overall contribution of the scheme to reliability and security of supply.

5.87. RBP also considered whether there should be a further requirement for the System Operator to assess the costs of the service *at the time of activation*. A requirement to confirm that total market costs (ie, total spot market costs, which are likely to be at scarcity pricing levels, plus ERS activation costs) are less than VoLL, will help ensure the overall outcome is efficient and the service provides overall consumer benefit.

5.88. However, this assessment may be complex and would need to be undertaken in a compressed time and in the context of managing a potential supply shortfall. Given this, the cost and practicality of undertaking this further assessment may exceed its benefit. The Authority welcomes views on the relative costs and benefits of requiring this additional assessment.

5.89. Whether used at the time of procurement or also activation, the level of VoLL is key to determining whether ERS should be procured and activated. The current level of

[40] Specifically, the forecast cost of ERS should not exceed VoLL multiplied by the estimated quantum of load that the System Operator forecasts would not be met in the absence of the ERS.
[41] We propose a transitional VoLL for the purposes of establishing the ERS by Winter 2026, if approved (see Section 7).

VoLL was set in the Code in 2004 and has not been adjusted since. We would use an adjusted VoLL for the ERS ahead of planned review of VoLL; this is discussed in Section 7 below.

Allocation of costs to loads is likely to enhance efficiency

5.90. The Authority proposes that the costs of the ERS be allocated to 'loads', including retailers and consumers who participate directly in the spot market. The ERS will benefit consumers overall by providing enhanced reliability of supply for consumers during infrequent, emergency events.

5.91. Pre-event and event costs would be allocated separately:

(a) pre-event costs (preparation and availability fees) should be allocated to loads based on their share of monthly metered consumption in relevant months

(b) event costs (pre-activation and activation fees) should be allocated to loads based on their metered consumption during activation events.

5.92. This approach is consistent with RBP's recommendation. While generators may be considered a 'causer' of the need for the service, allocating costs in part or whole to generators would result in less efficient market outcomes as:

(a) this would be unlikely to materially influence the incentives on generators to be available during peak demand periods

(b) costs will ultimately be passed through from generators to consumers

(c) allocating costs to loads provides retailers with information about their exposure to the cost and enables them to consider alternative options to manage the risk.

5.93. The Authority acknowledges, however, that there may be other ways of recovering costs. The proposed ERS is designed to provide benefits to consumers broadly, particularly during times of peak demand, and not necessarily in proportion to a consumers' actual consumption at the time of an emergency event. Other options include recovering costs from:

(a) loss and constraint rentals, which would avoid or limit any overall increase in market costs of delivering the service[42]

(b) loads, allocated in proportion to peak demand levels, which may strengthen incentives for consumers to minimise consumption at peak times.

5.94. The Authority welcomes feedback from stakeholders on these or alternative options for recovering ERS costs.

5.95. As recommended in the RBP report, we consider that costs should also be allocated nationally, not separately by island, to improve efficiency and be more equitable. Lower demand in the South Island may result in very high charges for any reserves procured and activated in the South Island. Such an approach also

[42] Loss and constraint rentals are a by-product of the nodal energy pricing used in the New Zealand wholesale electricity market. Rentals occur because the price paid and quantity received by purchasers is different to the price received and quantity provided by generators, due to line losses and transmission constraints. These rentals are used to fund trading in financial transmission rights (FTR) with any remainder returned (paid) to loads. More information on Loss and Constraint Excess Payment is provided by the System Operator. Such changes to cost allocation would likely require longer-term consideration to avoid undermining the FTR market.

discounts the role of the HVDC link. A shortage in the South Island could be alleviated by reducing interconnector flows, however, this would be detrimental to overall reliability and efficiency.

5.96. The Authority notes that the proposed cost allocation arrangements would result in some double payment by purchasers in the market who pay both scarcity prices and fund activation costs. However, this is not considered to materially detract from the benefits of the scheme, given likely infrequent use and the requirements for System Operator to seek to restrict costs via competitive tender and ensure costs are less than VoLL.

Settlement with providers can leverage existing processes for ancillary services

5.97. The Authority proposes that settlement of the ERS should occur in a similar manner to other ancillary services contracted by the System Operator, to minimise the cost and effort involved in establishing or modifying settlement processes by the System Operator and Clearing Manager.

5.98. Where aggregations are providing the ERS, it is anticipated that the aggregator will submit aggregated measurement data for its portfolio to facilitate settlement calculations. This approach is recommended by RBP as a lower-cost option. While the System Operator would need to develop a process to verify the quality of the data provided, it will not be required to establish a system to directly monitor the consumption of loads within an aggregation.

Performance management

Performance management should provide confidence in service delivery without discouraging participation by capable providers

5.99. For an ERS to effectively support the reliability and efficiency of the electricity system, service providers need adequate incentives to deliver the service in accordance with the relevant specification, and the System Operator needs to have confidence that providers will perform as expected. Measures to ensure performance can be both proactive (ie, to confirm capability ahead of an activation) and reactive (to discourage and address non-performance).

5.100. We propose several measures to ensure performance, consistent with RBP’s report and Transpower’s current practice, as the grid operator, for grid support contracts:

(a) As part of the procurement process, prior to contracting, the System Operator should perform due diligence to ensure the provider has the technical and commercial capability to deliver the offered service.

(b) ERS contracts should include provisions for the System Operator to undertake reasonable testing. Testing should be sufficient to confirm the performance of the service, but no more than required to keep costs to a minimum.

(c) As part of the procurement process, the System Operator should consider the risk of ‘resource fatigue’ which may result in diminished performance over time.

(d) The inclusion of a pre-activation step provides an opportunity for providers to prepare to provide the service and, if required, providers' pricing can include pre-activation costs.

(e) If an ERS provider fails to satisfy its performance requirements in an activation event without bone fide reasons, the service provider will forfeit activation and availability payments for the relevant period.

5.101. The Authority considers that these measures strike an effective balance between ensuring the ERS delivers on its reliability objective, without excessive impact on competition or the efficiency of the scheme.

5.102. RBP also considered whether providers should incur a penalty in the case of non-performance. Based on the experience with grid support contracts, we do not propose to use penalties. Doing so would likely be a significant barrier to entry and reduce participation and competition within the scheme.[43]

Information provision and publication

Access to useful and timely information is essential to support effective operation and monitoring

5.103. Information published ahead of the operation of the scheme (eg, supply-demand forecasts and information about the procurement process) will help interested parties identify the likely need for, and scale of, any future ERS procurement, and the requirements of the scheme.

5.104. Once procurement has been triggered, information about the use of ERS and the associated costs are essential to enable monitoring of the scheme's effectiveness.

5.105. We support RBP's recommendation that the following information be published by the System Operator:

(a) Annual Expected Unserved Energy (EUE) assessment setting out the quantum, location and duration of any potential shortfalls. This will provide an early indicator to potential providers that the service might be required and facilitate market testing and panel selection activities by the System Operator.

(b) Regular publication of the NZGB including the N-1 balance, as already occurs, to trigger procurement and pre-activation activities as required.

(c) Information required to support making an offer to provide ERS, including:

(i) standardised ERS contracts proposed by the System Operator

(ii) expressions of interest information for market testing, including the service specification and technical requirements of the service, determined by the System Operator.

(d) Quarterly updates of ERS procurement activities, including the quantities procured and the contracted compensation.

(e) Quarterly updates of activation activities including:

(i) frequency and quantity of shortfalls

[43] Refer to section 2.5.3 of RBP's report in Appendix A.

(ii) quantities pre-activated, by event

(iii) quantities activated, by event

(iv) total costs, by event

(v) unit cost, by event.

5.106. We also recognise that some information about the operation of the ERS will be important to assess the effectiveness and performance of the scheme but is not well-suited to publication in detailed form. We propose the following information should be provided by the System Operator to the Authority, as set out by RBP:

(a) the number of providers and their offer details

(b) the providers selected and the rationale for their selection

(c) forecast ERS costs based on selection.

5.107. Provision and publication of this information (as appropriate) will ensure that lessons learnt from the operation of the scheme can be identified and, if needed, the scheme can be enhanced over time.

Questions

Q3. Do you agree with our proposal that only demand-side flexibility, including by industrials and aggregations of smaller consumers, should be eligible to provide ERS?

Q4. Are you aware of any off-market generation or batteries that may not be activated in an emergency if they are not included in an ERS? Please provide details of the type and scale of these resources.

Q5. Do you agree with our proposed design elements for procurement of ERS by the System Operator, including the procurement process, timing and trigger?

Q6. Do you consider that procurement up to 4 weeks in advance of an identified need, coupled with a pre-approved panel of providers, will be effective and provide adequate time for potential providers and the System Operator?

Q7. Do you agree with our proposed pre-activation and activation processes for use of ERS?

Q8. Do you agree that the System Operator should be required to update relevant planning processes to take account of forecast uncertainty? If so, how do you consider this should be done?

Q9. Do you agree with our proposed compensation and price settings for the ERS, including proposed measures to ensure overall unit costs do not exceed VoLL?

Q10. Do you consider that the System Operator should also be required to ensure overall costs during an ERS activation are less than VoLL? If so, how do you consider this could be practically achieved in the available time?

Q11. Do you agree with our proposal to 'add back' activated ERS into nodal load schedules to maintain scarcity pricing?

Q12. Do you agree with our proposed settings for cost allocation and settlement of ERS costs? Do you consider an alternative cost recovery approach would be preferable and if so, why?

Q13. Do you agree with our proposed settings to manage non-performance by ERS providers?

Q14. Do you agree with our proposed information and publication settings to enable the effective operation and monitoring of the ERS? Is there additional information you consider should be made available to potential providers, the Authority, other industry participants or the public?

Q15. Are there other scheme design elements that the Authority should consider?

6. Preliminary evaluation against guiding principles

6.1. In our issues and options paper, we proposed a set of guiding principles for any actions. These are set out in Appendix B and summarised in paragraph 4.30.4.30

6.2. Table 1 provides a preliminary evaluation of the proposed ERS design against the guiding principles proposed in the issues paper, which are aligned with our main statutory objective. We are interested in your feedback on this evaluation.

Table 1: Preliminary evaluation of proposed ERS against our guiding principles

Principle	Evaluation of proposed design
Enable diversity of parties competing to bring solutions	Competitive tender process, flexibility in payment structure, transparency, and avoidance of penalties for non-performance to encourage maximum participation and competitive tension. Exclusion of generation and batteries not considered a material detriment – these resources should participate in spot market, or in the case of local generation is likely to already have been dispatched in a grid emergency (ie, no additionality).
Ensure the secure and reliable supply of electricity	Enables access to additional demand flexibility to help balance demand and supply and minimise the risk of involuntary load shedding. Balanced performance requirements to provide confidence in service delivery while maximising participation.
Enable efficient operation and minimise costs for consumers in the long run	Only procured and activated if needed, based on the best forecasts possible by delaying procurement as late as practicable. Costs should not exceed VoLL. Scarcity pricing to be maintained in the spot market to provide long-term investment signals. Additionality requirements to avoid withdrawal of capacity from other mechanisms.
Minimise cost, complexity and effort of participation	Flexibility in terms for providers and the System Operator. Aligns with and uses existing processes as far as practicable. Avoids the need to develop, or significantly modify existing, market clearing and dispatch systems. Design approach is to be fit-for-purpose. Additional requirements to be included only if the benefits are expected to exceed the cost (eg, the requirement for the System Operator to assess costs at the time of activation (as well as procurement) discussed at paragraph 5.87).
Maximise strategic alignment with Task Force and Authority work programme	Consistent with proposed vision for industrial demand flexibility and may unlock demand flexibility from industrials and smaller consumers for wider use. Supports system security and reliability in the transition to more intermittent renewable generation.

6.3. RBP undertook a more detailed evaluation of the different design options; refer to Section 5 of this consultation paper and Appendix A of the RBP report.

6.4. The Authority has not yet sought to undertake a cost-benefit analysis for the ERS.[44] At this stage, we consider the costs and benefits to be sensitive to key elements of the scheme design. Key factors include the resources that may be eligible to participate and interactions with existing market and grid emergency mechanisms.

6.5. If the Authority decides to continue developing an ERS for implementation, we will undertake a cost-benefit analysis as part of the detailed scheme design and Code design process.

Questions

Q16. Do you agree with our high-level evaluation of the proposed ERS against our guiding principles?

Q17. Is there any additional information the Authority should consider in evaluating a proposed ERS design?

44 We note that Mercury' submission to the issues and options paper suggested a cost-benefit assessment be undertaken for the proposed ERS.

7. Implementation and related issues

The Authority welcomes early feedback on the implementation of an emergency reserve scheme for winter 2026

7.1. Following consideration of the feedback on this ERS consultation paper, the Authority will decide whether to proceed with an ERS, intended to be in place for winter 2026.

7.2. Given the tight implementation timeframe, we have already begun to provisionally consider implementation scenarios and related issues and have sought early input from the System Operator. While our thinking is preliminary at this stage, we welcome any feedback from stakeholders on matters relevant to the implementation of such a scheme.

An emergency reserve scheme may need to be delivered in stages

7.3. The Authority acknowledges that both the System Operator and potential providers would need time to prepare for the scheme's operation, and some changes will take longer to implement than others.

7.4. While our preference would be to fully implement the scheme from the outset, we consider it is likely that it would need to be implemented in a staged manner. Therefore, should the Authority proceed, initial implementation could be limited to a 'minimum viable product' version of the ERS. This also provides an opportunity to learn-by-doing and evolve the scheme in response to experience and market conditions over time – or even to suspend it should market conditions change.[45]

7.5. We also acknowledge that amendments would also be required to System Operation Documents, which are developed by the System Operator and approved by the Authority. This will require further work with the System Operator to determine the nature and scope of these changes.

7.6. Possible staging options include, but are not limited to:

(a) commencing the scheme with participation by industrial demand flexibility providers (given they are large, single Grid Exit Point, loads) and adding other forms of flexibility at a later point in time.[46] This could provide the System Operator and potential providers more time to establish the technical requirements for aggregations (eg, for communications, performance management and response measurement)

(b) earlier commencement of procurement of the service (eg, more than 4 weeks ahead) to enable management of any 'teething issues', particularly if there is not time to establish a pre-qualified panel of providers the first time the scheme is used

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[45] Transpower and EEA both encouraged an approach of incremental improvement in their submissions to the issues and options paper, and Transpower also suggested consideration of a time-limited scheme, ahead of other firm/flexible capacity entering the market.

[46] Transpower's submission also suggested there could be benefits of commencing the scheme with industrials and EnelX's submission noted that focussing on industrials could be a lower risk first step, while advocating for technology agnostic solutions overall.

(c) providing additional time for the System Operator to develop elements of the scheme that may be more complex or require greater stakeholder input, such as testing and verification arrangements, and updates to forecasting tools.

Emergency reserve scheme operation is influenced by key market settings

Value of Lost Load

7.7. As discussed in Section 5 above, VoLL has an important role to play in the ERS. VoLL represents the economic value that consumers place on foregone energy (ie, due to an outage) and therefore acts as an upper limit on the costs of emergency reserves, as it would be inefficient to pay more than VoLL to avoid an outage.

7.8. The current level of VoLL specified in the Code is $20,000 per MWh. This was set in 2004 and has not been adjusted since.

7.9. Several parties have identified the need to review and update New Zealand's VoLL settings, including the Authority in the Northland tower collapse report, MDAG,[47] and stakeholder feedback to the Peak Capacity and Scarcity Pricing projects. RBP's report also recommends that VoLL be reviewed periodically.[48]

7.10. Transpower and the Commission have adjusted VoLL for inflation in regulatory proposals. The Commission used an inflation-adjusted VoLL of $35,305/MWh in its most recent default price-quality path (DPP) determination for EDBs.[49]

7.11. The Authority recently updated settings for scarcity pricing in the spot market. These changes seek to ensure that spot prices (including scarcity prices) incentivise operational, contracting and investment decisions which ensure a secure and reliable electricity supply in both the short and longer term.

7.12. The Authority acknowledges that it would be appropriate to review the VoLL settings in the Code and is currently considering the scope and timing of a review.

Proposed VoLL setting for an emergency reserve scheme

7.13. For the purposes of establishing an ERS ahead of winter 2026 (if that proceeds), the Authority proposes to set a transitional VoLL value to be used only for the ERS. This VoLL setting could subsequently be replaced following a review of VoLL in the Code.

7.14. The Authority proposes to use the same figure determined by the Commission in the recent DPP determination for the ERS, namely $35,305/MWh. We note that this was determined by the Commission as the inflation-adjusted VoLL for the mid-point of the fourth DPP period (ie, 30 September 2027), which is later than the intended commencement of the ERS in winter 2026.

7.15. However, the Authority does not consider this timing mismatch to be significant enough to warrant use of a different figure. Doing so will also avoid the need to update the figure again for winter 2027, should any future updates to VoLL settings in the Code not be in place at that point.

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[47] MDAG, 11 December 2023, *Price discovery in a renewables-based electricity system final report*, recommendation 16.
[48] See section 2.5.1 of the RBP report in Appendix A
[49] Commerce Commission, 20 November 2024, *EDB DPP4 – Final decision – Reasons paper – Attachment E*.

Security standards

7.16. Security standards include the New Zealand Winter Energy Margin, South Island Winter Energy Margin and North Island Capacity Margin. These values are used by the System Operator in its annual SOSA. VoLL settings are used as an input to determine the EUE thresholds for the security standards, to ensure planning margins are set to limit uneconomic load curtailment.

7.17. In the context of the proposed ERS, RBP also recommended that the security standards be updated, to reflect any updated VoLL and to capture forecast uncertainty as discussed in Section 5 above.[50]

7.18. The Authority is currently reviewing the security standards and plans to publish a paper for consultation on potential changes to these before the end of the year. This will specifically consider how often the security standards should be updated.

Questions

Q18. Do you think there are any elements of the proposed scheme design which require more time for implementation and should be delayed beyond Winter 2026? If so, please identify the relevant elements and indicate when you consider they could be implemented.

Q19. Do you agree with the Authority's proposal to set VoLL at $35,305/MWh for the purposes of the ERS, and proposal to review VoLL and security standards more broadly?

Q20. Are you likely to be interested in participating in an ERS, such as the scheme outlined in this paper?

Q21. Are there any other implementation considerations or related issues the Authority should consider in relation to an ERS?

Q22. Are there other matters that the Authority should consider in relation to an ERS?

[50] See also section 2.3.1 of the RBP report in Appendix A.

8. Next steps

8.1. The Authority welcomes your feedback on this consultation paper by 28 August 2025. Your views will help inform whether we progress with the implementation of an ERS as part of our industrial demand flexibility roadmap and, if so, the design of the ERS.

8.2. If we decide to proceed with the implementation of an ERS in time for winter 2026, we propose the following key next steps:

(a) publish a Code consultation paper, targeted for release in October 2025

(b) finalise Code changes, targeted for December 2025

(c) commence the ERS to make it available for winter 2026.

Appendix A RBP Evaluation of Emergency Reserve Scheme Options report

Appendix B Proposed guiding principles for industrial demand flexibility roadmap initiatives

The Authority developed a set of principles to guide the proposed actions, which will also inform the further development and detailed design (where applicable) of actions over time.

The guiding principles have been developed with reference to the Authority's Statutory Objectives and the proposed vision for industrial demand flexibility, and has regard to the Government Policy Statement on Electricity. The principles also include practical considerations (ie, costs) and the broader strategic context in which the roadmap is being developed. As the Authority is in the process of considering submissions on the issues and options paper, these guiding principles remain unchanged at this stage.

Principle	Outcomes sought
Enable diversity of parties competing to bring solutions that meet customer demand	• Providers have access to information that enables them to develop business models to provide intra-day flexibility services using industrial demand flexibility. • Competition in the provision of flexibility services is maximised with diversity of parties offering and seeking to purchase flexibility services. • Network business processes enable non-network solutions to compete on a level playing field with traditional network solutions. • Market concentration does not unduly limit liquidity in the trade of flexibility products. • Large consumers, retailers and third-party service providers can all offer services (either themselves, or on behalf of consumers). • Wider competition in the New Zealand electricity market is not distorted. • Efficient incentives are available to all providers of flexibility services.

Principle	Outcomes sought
Ensure the secure and reliable supply of electricity	• Demand response is activated to ensure we limit the amount of unserved energy to economic levels. • Providers have effective incentives to be available and/or disincentives for non-performance. • Network businesses are adequately incentivised to consider demand flexibility as an alternative to network investment. • Service delivery and performance can be forecast and measured with sufficient accuracy. • Providers are given sufficient notice for resources to be available.

Enable efficient operation of the electricity industry and minimise costs for consumers in the long run	• Use of industrial demand flexibility provides long-term value to consumers in aggregate (eg, by deferral of generation and/or network investments, which reduces up front impacts on consumer bills).
	• Pricing is efficient and incentivises entry and consistent provision of demand flexibility over time (ie, pricing covers both operating and capital costs and can provide a reasonable return that, together, do not exceed the value of the demand response to consumers in aggregate).
	• Providers have access to information and services to accurately identify and manage their risks.
	• Triggers for the activation of demand flexibility are set to minimise any efficiency loss.
	• Use of demand flexibility should not:
	  o distort wholesale market pricing by incentivising providers to withdraw capacity
	  o distort scarcity pricing signals in the wholesale market
	  o displace lower-cost energy resources.
	• Incentives for providers should be predictable and 'first movers' should not be disadvantaged.

Minimise cost, complexity and effort of participation for demand response providers	• Actions taken to activate demand flexibility are proportionate to the value of any additional demand flexibility likely to be made available – currently and into the future. • Costs and effort of providing or purchasing demand flexibility are minimised and do not exceed benefits. (Costs include regulatory, market systems, participant systems, telemetry, system operations, settlement and reconciliation, etc.)

Principle	Outcomes sought
	• Where possible, replicable, standardised processes and systems are developed to reduce cost (eg, standard processes for notifying the market of demand flexibility opportunities across all 29 distributors). • Compliance requirements for demand flexibility providers are minimised but sufficient to ensure that competition, reliability and efficiency of the electricity system are not compromised.

Maximise strategic alignment with the broader Task Force and Authority work programme	• Actions to enable industrial demand flexibility are aligned with broader changes in the electricity system, including:
	  ○ alignment (and not duplication) with other reform initiatives
	  ○ the potential for more efficient supply of flexibility by other providers of flexibility services (including aggregations of small consumers' resources) immediately and in the future
	  ○ the potential for demand flexibility providers to value stack across compatible demand response services
	  ○ the evolving needs of the power system and capability of demand response.
	• We prioritise enduring solutions but remain open to 'learning by doing' where necessary.

Appendix C Format for submissions

Submitter	

Questions	Comments
Q1. Do you agree with our rationale for establishing an ERS? Why/why not?	
Q2. Are there other factors or risks you consider relevant to our decision to implement an ERS?	
Q3. Do you agree with our proposal that only demand-side flexibility, including by industrials and aggregations of smaller consumers, should be eligible to provide ERS?	
Q4. Are you aware of any off-market generation or batteries that may not be activated in an emergency if they are not included in an ERS? Please provide details of the type and scale of these resources.	
Q5. Do you agree with our proposed design elements for procurement of ERS by the System Operator, including the procurement process, timing and trigger?	
Q6. Do you consider that procurement up to 4 weeks in advance of an identified need, coupled with a pre-approved panel of providers, will be effective and provide adequate time for potential providers and the System Operator?	

Questions	Comments
Q7. Do you agree with our proposed pre-activation and activation processes for use of ERS?	
Q8. Do you agree that the System Operator should be required to update relevant planning processes to take account of forecast uncertainty? If so, how do you consider this should be done?	
Q9. Do you agree with our proposed compensation and price settings for the ERS, including proposed measures to ensure overall unit costs do not exceed VoLL?	
Q10. Do you consider that the System Operator should also be required to ensure overall costs during an ERS activation are less than VoLL? If so, how do you consider this could be practically achieved in the available time?	
Q11. Do you agree with our proposal to ‘add back’ activated ERS into nodal load schedules to maintain scarcity pricing?	
Q12. Do you agree with our proposed settings for cost allocation and settlement of ERS costs? Do you consider an alternative cost recovery approach would be preferable and if so why?	
Q13. Do you agree with our proposed settings to manage non-performance by ERS providers?	

Questions	Comments
Q14. Do you agree with our proposed information and publication settings to enable the effective operation and monitoring of the ERS? Is there additional information you consider should be made available to potential providers, the Authority, other industry participants or the public?	
Q15. Are there other scheme design elements that the Authority should consider?	
Q16. Do you agree with our high-level evaluation of the proposed ERS against our guiding principles?	
Q17. Is there any additional information the Authority should consider in evaluating a proposed ERS design?	
Q18. Do you think there are any elements of the proposed scheme design which require more time for implementation and should be delayed beyond Winter 2026? If so, please identify the relevant elements and indicate when you consider they could be implemented.	
Q19. Do you agree with the Authority's proposal to set VoLL at $35,305 per MWh for the purposes of the ERS, and proposal to review VoLL and security standards more broadly?	

Questions	Comments
Q20. Are you likely to be interested in participating in an ERS, such as the scheme outlined in this paper?	
Q21. Are there any other implementation considerations or related issues the Authority should consider in relation to an ERS?	
Q22. Are there other matters that the Authority should consider in relation to an ERS?	

Appendix D Glossary of key terms

Additionality	In this context means that resources procured are 'additional to' what would have happed if the mechanism had not been put in place (eg, continued as business-as-usual).
AEMO	Australian Energy Market Operator
Aggregators	Entities that group together different resources. In the context of this paper, the terms refer to aggregators of different actors' demand flexibility resources.
Ancillary services	Additional services procured by the System Operator to support the reliable operation of the power system and assist it to meet its Principal Performance Obligations specified in the Electricity Industry Participation Code.
AUD	Australian dollars
Black start	The first step in the process of system restoration in the unlikely event of an island-wide black-out.
Code	Electricity Industry Participation Code
Controllable load	Load (eg, hot water cylinders) that a consumer (or someone on its behalf) can reduce to help reduce demand during peak times or to respond to a grid emergency.
DD	Dispatchable demand. A regime that enables demand-side participants to compete with generators to set the spot price and be able to respond more efficiently to wholesale market conditions.
Demand flexibility	Consumers adjust the time and/or the amount of their electricity consumption (demand) in response to market and network conditions. Generally, this involves reducing demand in response to high wholesale prices or congestion in the electricity network.
DER	Distributed energy resources, such as solar PV systems, batteries and controllable appliances at consumers' premises.
DFS	United Kingdom's Demand Flexibility Service
DNL	Dispatch notification. A low-cost path to allow small scale generation and aggregated resources to directly participate in the spot market.
Economic load shedding	Load shedding in the circumstances where a consumer is unwilling to pay more than the cost of the additional action (ie, more supply, or reduced demand by other consumers) required to balance demand and supply and avoid an outage. The upper limit on the

	price consumers are notionally willing to pay to avoid an outage is referred to as the Value of Lost Load.
EDBs	Electricity distribution businesses. Also called network companies, distribution companies or distributors. These are lines companies that own and operate the lower voltage power lines and distribution networks in local areas. These connect to the national grid to deliver electricity to homes and businesses.
Emergency load shedding or involuntary demand curtailment / shedding	When the System Operator instructs EBDs to reduce demand to a level that can be supplied to ensure stability of the power system.
Energy Competition Task Force (Task Force)	The Authority and Commerce Commission have jointly established it to investigate ways to improve the performance of the electricity market.
ERCOT	The Electricity Reliability Council of Texas
ERS	Emergency reserve scheme. A mechanism to be activated as a 'penultimate resort' – ahead of involuntary load shedding. The ERS would use pre-contracted demand flexibility to provide this service.
EUE	Expected Unserved Energy. This assessment sets out the quantum, location and duration of any potential shortfalls.
Flexibility provider	An actor (such as third-party aggregators) who provides flexibility services by making temporary changes to the way they, or contracted consumers, consume, generate, or store electricity when requested by the electricity networks or System Operator.
Flexibility services	They draw on consumer flexibility and distributed energy resources (eg, controllable electric vehicle chargers or solar generation) to provide support services to distribution networks, the transmission grid and energy markets.
GEN	Grid Emergency Notice issued by the System Operator.
Industrials	For this initiative, the term includes large direct-connect consumers along with medium size commercial and industrial consumers that are not directly connected to the transmission system, but have large, disaggregated loads (eg, supermarkets).
Intermittent generation	Electricity generation that relies on a variable resource that is not stored (eg, wind and solar).
Intra-day flexibility	Flexibility to made available to account for short-term variability during the day (as opposed to seasonal flexibility).

Low residual events	Events when the remaining offered capacity (residual) for a given trading period drops to a level that increases the risk of a grid emergency and potential demand management.
MDAG	Market Development Advisory Group. One of the Authority's advisory and technical groups. The group provided independent advice on issues that relate to pricing and cost allocation, risk and risk management, and operational efficiencies. The group was formed in October 2017 and disbanded in February 2024.
Moral hazard	When a party becomes more inclined to take a particular risk because they believe another party (ie, an insurer) will cover the costs of any damage.
N-1 balance	The balance between supply and demand if the biggest risk (eg, the largest generator) is removed (eg, due to an unplanned outage).
NEM	Australia's National Electricity Market
NESO	United Kingdom's National Energy System Operator
NRSS	Non-Response Schedule Short. It assumes all loads consume at the maximum level indicated in their bids (and ignores any indicated price responsiveness). It is solved every 30 minutes (short schedules) and 2 hours (long schedules).
NZGB	New Zealand Generation Balance. It forecasts whether there will be enough generation capacity to meet potential peak demand on the power system over the next 200 days.
Peak	In this context period of high electricity demand and high pricing.
Peak capacity risk	Risk that there may not be enough generation and transmission assets to meet peak electricity demand at any point in time.
Power Innovation Pathway	Authority's approach to provide enhanced regulatory support to high-value initiatives to accelerate New Zealand's energy transition.
RBP	Robinson Bowmaker Paul. The consulting agency that considered several alternative options for elements of the ERS design (Appendix A)
RERT	Reliability Emergency Reserve Trader. A mechanism administered by Australian Energy Market Operator to maintain power system reliability and system security during periods of high demand-low supply using reserve contracts.
Retailer	A company that sells electricity or gas to consumers.

SOSA	Security of Supply Assessment. This assessment uses forecasts of electricity supply and demand to assess the ability of the electricity system to meet New Zealand's needs over the decade ahead. The System Operator publishes it annually.
Spot market	The spot or wholesale market is a marketplace to buy and sell electricity.
TERS	Texas Emergency Response Service
Supplementary Capacity	A mechanism to maintain power system security and reliability. It can be triggered by AEMO in Western Australia's South West Interconnected System.
SWIS	Australia's South West Interconnected System
Uneconomic load shedding	A situation where we shed load even though consumers would have been willing to pay a price higher than the prevailing spot market price to avoid an outage.
VoLL	Value of lost load. A measure of the cost of outages experienced by customers (ie, trading loss during business hours).
WDS	Week-ahead Dispatch Schedule. Provides an initial indication of market conditions up to eight days ahead.
Wholesale market	The wholesale or spot market is a marketplace to buy and sell electricity.