Emergency reserve scheme: Code amendment

Decision paper

13 January 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

On 17 October 2025, the Electricity Authority Te Mana Hiko (Authority) published the *Emergency reserve scheme – Code amendment proposal* (Code amendment proposal consultation paper). The paper outlined our in-principle decision to establish an emergency reserve scheme (ERS) and set out a draft amendment to the Electricity Industry Participation Code 2010 (Code) that would give effect to this in-principle decision.

The proposed ERS aims to enhance the reliability of New Zealand's electricity system by providing an additional tool for the System Operator to use in periods of acute system stress to help manage critical supply shortfalls over short periods of time.

In response to the Code amendment proposal consultation paper, we received six submissions, all of which supported the establishment of the ERS.

The Authority confirms the decision to amend the Code to establish the ERS in the form of a new ancillary service called 'emergency reserve'.

We have refined our Code drafting in response to feedback

The Authority has made minor changes to the proposed Code amendment after considering feedback from submitters. These changes:

- Modify the eligibility requirements to enable providers to participate in the ERS who would previously have been excluded on the basis that they had provided certain services in the wholesale electricity market, or in response to another contract or arrangement, in the previous 12 months. Providers will now not be excluded if:
    - they were a provider of interruptible load in the previous 12 months, provided that they are no longer offering this service. We recognise that recent changes to the market dynamics for instantaneous reserves may otherwise see these providers exit the market entirely; or
    - they are no longer able to provide the service in the wholesale market due to circumstances outside of their control.
- Provide the System Operator with flexibility when it determines the method for ensuring wholesale market prices are maintained at scarcity levels when the ERS is activated.

We have also made some minor additional changes to the proposals contained in the Code amendment consultation paper which we consider to be necessary and non-controversial. We have:

- included an inflation-adjusted Value of Lost Load (VoLL) in clause 4 of Schedule 12.2 of the Code for the purposes of the ERS, set at $35,305 per MWh (consistent with our previous consultations);
- amended Clause 8.54BA to require the System Operator to report the costs of the scheme against VoLL in its post event reporting, which is important for demonstrating that the ERS is achieving the desired policy intent;
- made an amendment to a term used in clause 8.58A, which sets out how emergency reserve costs are allocated, in order to correct a minor inconsistency; and
- made other minor editorial changes to ensure consistency in style and use of terms.

We have amended our target implementation date and further detailed the implementation phase

In response to submitters' concerns, we have amended our target for implementation of the ERS from winter 2026 to Q4 2026.

While we consider that the ERS should be implemented as soon as possible, we acknowledge the potential for significant implementation risks should this occur too quickly. It is also likely that the initial winter 2026 timing would limit the ability of potential ERS providers to engage with the System Operator on implementation and operational matters, and that this could affect participation. This may limit the ability of the ERS to support system security and could also increase the costs of the scheme.

We agree with submitters that the need for emergency reserves may arise at any time of year, as periods of inadequate supply can occur outside of peak winter demand periods, such as due to outages of generation or transmission infrastructure.

In line with our proposed approach, the System Operator has been working to identify concepts for a minimum viable product. This is still in development, and the Authority and System Operator will engage with industry on this in due course.

We also consider that, to facilitate timely implementation and encourage early participation by providers:

- the System Operator could undertake a co-design process with potential providers to determine the technical requirements of the emergency serve service, which are to be set out in the Ancillary Services Procurement Plan (Procurement Plan);
- the initial procurement of ERS could initially be limited to a smaller pool of providers with relevant capability and experience, with potential providers identified in the co-design process; and
- the System Operator could initially elect to procure the service for a minimum period (eg, three to six months), to give providers confidence in their ability to recover their costs during the early operation of the scheme.

Over time, as both the System Operator and providers gain experience with the ERS, the requirements and procurement timeframes for emergency services can be refined and participation expanded to a broader pool of eligible providers.

Next steps

The Code amendments establishing emergency reserve as an ancillary service will come into force on 1 March 2026.

The Authority will support the System Operator and Clearing Manager to undertake the necessary steps to implement the ERS by Q4 2026, including:

- developing the Procurement Plan and associated documents (eg, contract templates) for emergency reserve;
- establishing internal processes for the procurement, activation, and reporting of the ERS; and
- introducing any necessary system changes to facilitate the procurement and activation of emergency reserve or recovery of emergency reserve costs.

Contents

1. Purpose

1.1. The Electricity Authority Te Mana Hiko (Authority) has decided to amend the Electricity Industry Code 2010 (Code) to establish an emergency reserve scheme (ERS).

1.2. This follows our *Emergency Reserve Scheme – Code amendment proposal* (Code amendment proposal consultation paper), which set out proposed amendments to the Code to establish an emergency reserve ancillary service.

1.3. This paper:

(a) sets out our final decision to amend the Code to establish an ERS;

(b) explains the purpose of the ERS, what was proposed in the Code amendment proposal consultation paper, and the submissions we received in response to it;

(c) discusses changes we have made to the proposal, having considered points raised by submitters and engaged further with the System Operator on how it can be implemented;

(d) explains why we consider that our proposal, with the changes discussed in this paper, is preferable to alternatives;

(e) discusses how our decision supports our statutory objective;

(f) outlines the next steps, including to establish a minimum viable product (MVP) of the scheme during 2026; and

(g) sets out the final Code amendment.

2. We have decided to amend the Code to establish an emergency reserve ancillary service

2.1. This section provides an overview of the key features of the emergency reserve ancillary service that will be implemented via the Code amendment.

We will amend the Code to establish an emergency reserve ancillary service

2.2. The Authority has decided to progress with a modified version of the proposed amendment outlined in our Code amendment proposal consultation paper.

2.3. We have made the following changes after considering feedback from submitters:

(a) Amended the definition of emergency reserve in Part 1 to enable providers to participate in the ERS who would previously have been excluded on the basis that they have provided a service in the wholesale electricity market or in response to another contract or arrangement in the previous 12 months. Providers will now not be excluded if:

(i) they were a provider of interruptible load in the previous 12 months, provided that they are no longer offering this service; we recognise that recent changes to the market dynamics for instantaneous reserves may otherwise see these providers exit the market entirely; or

(ii) they are no longer able to provide the service due to circumstances outside of their control.

(b) Amended the proposed drafting of clause 3 in schedule 13.3AA to provide flexibility for the System Operator to determine the method for ensuring wholesale market prices are maintained at scarcity levels when load is reduced due to the activation of emergency reserve.

2.4. The rationale for these changes is discussed in section 5 below.

2.5. We have also made the following changes, identified by the Authority as necessary and appropriate following the publication of the Code amendment proposal consultation paper:

(a) Included an inflation-adjusted VoLL in clause 4 of Schedule 12.2 of the Code for the purposes of the ERS, which is $35,305 per MWh as proposed in our previous consultation on the ERS.

(b) Amended Clause 8.54BA to require the System Operator to report the costs of the scheme against VoLL in its post event reporting, which is important for demonstrating that the ERS is achieving the desired policy intent.

(c) Made a minor amendments to a term used in clause 8.58A, which sets out how emergency reserve costs are allocated, in order to correct a minor inconsistency.

(d) Made other minor editorial changes to ensure consistency in style and use of terms.

2.6. We note that the Ancillary Services Procurement Plan (Procurement Plan) will need to reflect the triggers for procuring and using emergency reserves and the technical requirements of the ERS. The System Operator is responsible for developing and amending the Procurement Plan. Section 0 provides further detail on the next stage of implementation of the emergency reserve ancillary service.

Summary of the emergency reserve ancillary service

2.7. Table 1 summarises the key design elements of the emergency reserve ancillary service, including the amendments outlined in section 5.

2.8. As noted in the Code amendment proposal consultation paper, much of the detailed design of the ERS will be set out in the System Operator's documents, in particular the Procurement Plan, and contracts with ERS providers. This is consistent with the approach for existing ancillary services.

Table 1: Final decision – key design elements for the emergency reserve ancillary service

Scheme element	Key design
Eligibility	Demand flexibility, including aggregations, and off-market generation are eligible to provide emergency reserves, provided they can meet the additionality and service requirements set out in the Procurement Plan and the contracts determined by the System Operator. Providers are generally excluded from providing emergency reserves where they have participated in the wholesale electricity market or have provided a similar service under a contract or other arrangements within the previous 12 months. This exclusion, however, does not apply to providers of interruptible load (provided they are no longer offering this service) or where the provider is no longer able to provide the service due to circumstances outside of the provider's control.
Procurement	The System Operator should procure emergency reserve as close as possible to the period for which it expects the service will be required. Ideally this will occur up to four weeks ahead of an identified potential shortfall, via a competitive tender process. The trigger methodology and service requirements will be set out in the Procurement Plan and determined by the System Operator. The System Operator may establish a pre-approved panel of providers in advance of procurement.
Activation	The System Operator can activate emergency reserve in a grid emergency after the operation of all market and business-as-usual mechanisms (eg, contracted demand response and the use of electricity distribution business (EDB) controllable load) and ahead of involuntary load curtailment. After all business-as-usual mechanisms have operated (including the use of EDB controllable load resources), the System Operator should: • pre-activate emergency reserve up to 36 hours ahead of real time; and • activate emergency reserve up to one hour ahead of real time. The System Operator should add back into the nodal load schedule any demand reduction because of the activation of ERS, or it should take an equivalent action. This is to ensure prices remain at the level they would have been without ERS activation.

	The trigger methodology and service requirements will be set out in the Procurement Plan and determined by the System Operator.
Pricing and settlement	ERS providers can recover both pre-event and event fees. They can determine these fees on an individual basis and set them out in their contract with the System Operator. The System Operator must make reasonable endeavours to ensure that the anticipated costs of ERS are less than VoLL (on a per-unit basis). ERS costs are to be recovered from purchasers on a national basis: • **pre-event costs** are allocated to loads based on their share of monthly metered consumption in relevant months; and • **event costs** are allocated to loads based on their metered consumption during activation events.
Performance management	The System Operator should include performance management measures in the process of procurement and pre-activation (eg, due diligence, consideration of resource fatigue, and effective communication). It should also include performance requirements in the Procurement Plan and ERS contracts. ERS contracts should provide for testing, along with forfeiture of payments proportionate to any non-performance.
Information and publication	The System Operator should publish: • the forecasts on which it bases its decision to procure and activate emergency reserve; • information to support the procurement of emergency reserve as part of the Procurement Plan and associated contract documents; and • details of the use and expected cost of emergency reserve within 20 business days following any use of the service. The System Operator's periodic reporting should include information about the procurement and use of emergency reserve, to be specified in the Procurement Plan. The System Operator should also provide the Authority with further details of the procurement and cost of emergency reserve, to be specified in the Procurement Plan.

3. We consulted on proposed Code changes and have considered the submissions received

3.1. On 17 October 2025, we published the Code amendment proposal consultation paper, which set out our intention to establish a new emergency reserve ancillary service. The ERS is intended to support the security and reliability of New Zealand's power supplies during rare and relatively short periods of time when limited supply results in a risk of involuntary curtailment of supply to customers.

3.2. This section sets out the background to this decision, including:

(a) what the ERS is and our rationale for developing it;

(b) our consultation on proposed Code changes to establish the ERS, including the key design elements of the ERS; and

(c) the submissions we received in response to our consultation.

3.3. Subsequent sections of this paper explain that submissions agreed with our in-principle decision to establish an ERS to support the security and reliability of New Zealand's electricity system. However, submissions on our Code amendment proposal consultation paper, and further engagement with the System Operator on the implementation of the ERS have led us to revise:

(a) some elements of the Code drafting to establish the ERS; and

(b) our target implementation date (from winter 2026 to Q4 2026).

We proposed an ERS to support electricity system security and reliability

3.4. An ERS has the potential to support a reliable and efficient electricity system by helping balance supply and demand to prevent, or reduce the extent of, uneconomic load shedding.[1]

3.5. An ERS would provide a means for purchasers to pay for additional reliability on behalf of consumers when these infrequent events occur. As long as that payment is less than the 'cost' of the alternative – an involuntary power cut – the ERS would contribute to an efficient electricity supply.

3.6. Grid emergencies due to a shortfall of supply to meet demand occur infrequently. However, the System Operator and the Authority consider that there is an increasing risk of such events due to changes to the supply and demand of electricity in New Zealand – in particular due to the transition to intermittent renewable generation and also from limitations on thermal fuel for generation (notably limitations on gas).

3.7. 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 be used ahead of involuntary load shedding to support security of supply.

3.8. In addition to promoting a more secure and reliable supply, an ERS could also help unlock efficient demand flexibility. Our previous work indicates demand flexibility can

[1] '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.

be a lower cost alternative to additional supply when it is only expected to be used infrequently.

3.9. Accordingly, we have stated two objectives for the ERS:

(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 inadequate supply is available from other sources; and

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

We have consulted on the design of an emergency reserve scheme and proposed Code drafting

3.10. The features of the emergency reserve ancillary service have been consulted on three times:

(a) Consultation by the Energy Competition Task Force on the *Rewarding industrial demand flexibility – Issues and options paper* (the issues and options paper) published on 28 May 2025, in which the Authority indicated its intention to develop a proposal for an ERS.

(b) *Establishing an Emergency Reserve Scheme consultation paper* (ERS consultation paper) published on 31 July 2025, in which we considered an submissions responding to the issues and options paper, and in which we set out our rationale for, and high-level design of, an ERS.

(c) The Code amendment proposal consultation paper published on 17 October 2025, in which we considered feedback on the ERS consultation paper and set out proposed Code changes to implement a new emergency reserve ancillary service.

Our Code amendment proposal outlined the high-level design of the emergency reserve scheme

3.11. As we outlined in our Code amendment proposal consultation paper, the ERS has six key design elements:

(a) eligibility to participate;

(b) procurement;

(c) activation;

(d) pricing and settlement;

(e) performance management; and

(f) information provision and publication.

3.12. As noted in section 2.2 above, we have largely maintained the design proposed in the Code amendment proposal consultation paper, with the following changes:

(a) Expanded eligibility to include, in certain circumstances, providers of interruptible load and of other services, even where those services have been provided within the previous 12 months.

(b) Provided flexibility for the System Operator to determine the method for ensuring wholesale market prices are maintained at scarcity levels when load is reduced due to the activation of emergency reserve.

3.13. We have also given further consideration to the implementation of the scheme to enable an MVP to be established as soon as practicable. We discuss the implementation of the ERS in section 0 of this decision paper.

Our Code amendment proposal consultation paper also set out proposed amendments to the Code

3.14. The Authority proposed to amend Parts 1, 8 and 13 of the Code to establish the ERS as a new ancillary service known as 'emergency reserve'. Code changes were identified to enable the System Operator to:

(a) procure and use emergency reserves;

(b) provide for the recovery of emergency reserve costs; and

(c) manage interactions with other mechanisms used to maintain the security and reliability of the power system in emergency situations.

3.15. The proposed Code amendments, set out in Appendix A to the Code amendment proposal consultation paper, to establish emergency reserve sought to:

(a) establish the new emergency reserve ancillary service and enable the recovery of emergency reserve costs. The Authority proposed new clauses in Part 8 of the Code, along with new and amended definitions in Part 1

(b) integrate emergency reserve into grid emergency processes and ensure that wholesale market prices are not affected by any demand reduction due to the activation of emergency reserve. The Authority proposed amendments to Schedule 8.3 – Technical Code B and Schedule 13.3AA

(c) address other interactions between emergency reserve and existing Code provisions, including requirements that should not apply to emergency reserve providers. The Authority proposed new and amended clauses in Parts 1 and 8, and to Schedule 8.3 – Technical Code B.

3.16. We also noted that emergency reserve providers would be required to register with the Authority under section 7 of the Electricity Industry Act 2010 (Act) and would be ancillary service agents under section 7(2) of the Act.

We received submissions on our Code amendment proposal consultation paper for emergency reserves

3.17. The Authority received six submissions on our Code amendment proposal consultation paper. Submissions were received from:

(a) Electrical Engineers' Association of New Zealand (EEA);

(b) Enel X;

(c) Major Electricity Users' Group (MEUG);

(d) Nova Energy (Nova);

(e) Transpower (as System Operator); and

(f) WEL Networks.

3.18. All submitters indicated support for the establishment of the ERS and, broadly, for its design. Submitters raised specific matters relating to the detailed design and operation of the scheme, which are discussed in the following section.

4. Submissions have confirmed our in-principle decision to establish an emergency reserve scheme

4.1. This section discusses our response to submissions about the need for and objectives of the ERS.

What we said

4.2. We indicated our in-principle decision to establish the ERS to help balance supply and demand to prevent, or reduce the extent of, uneconomic load shedding.

4.3. We considered that the primary objective of the ERS would be to promote system security and reliability, with a secondary objective of helping to build consumer capability to provide demand flexibility.

4.4. We acknowledged that there were risks associated with the establishment of an ERS. These include the potential to distort the operation of the wholesale electricity market, to increase costs, and to not provide additional resources that enhance the security of supply. However, we considered that these risks could be effectively managed through the design of the scheme.

Submitters generally supported our rationale and objectives

4.5. All of the submissions we received supported the establishment of the ERS. Several submissions also indicated support for the rationale and objectives of the scheme, with no submissions opposing them.

4.6. In relation to the objectives of the ERS, the submission from Enel X considered that a minor amendment should be made to the primary objective of the scheme, to remove the reference to high demand, as follows:

> ***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~~ inadequate supply is available from other sources.*

4.7. In support of its proposal, Enel X noted that periods of inadequate supply can occur outside of peak demand periods, such as due to outages of generation or transmission infrastructure. Transpower's submission also supported the potential need for the ERS outside of winter.

4.8. The EEA also suggested that the objectives of the ERS could be made more explicit in the proposed Code drafting.

Our assessment

4.9. The Authority confirms its decision to implement the ERS. We agree with the suggestion from Enel X that the primary objective of the scheme does not need to reference periods of high demand. The situation in which emergency reserves are required is when supply is inadequate, irrespective of the level of demand.

4.10. We have not made any changes to the Code drafting to more explicitly state the objectives of the ERS. Instead, consistent with other ancillary services, the Code definition of emergency reserve includes its purpose. This purpose, consistent with the Authority's objectives, is to "*minimise the electrical disconnection of demand in a grid emergency*".

5. We have refined our Code drafting in response to feedback

5.1. This section discusses the specific feedback we had on the key ERS design elements and proposed Code amendments outlined in our Code amendment proposal. We have followed the same structure as the key design elements outlined in Table 1 above.

Eligibility

What we said

5.2. We proposed that demand flexibility, including aggregations, and off-market generation would be eligible to provide emergency reserves. This was provided they could meet the additionality requirement and the service requirements determined by the System Operator.

5.3. We excluded battery energy storage systems (BESS) from participating in the scheme. The integration of BESS into the wholesale electricity market is being considered in our battery energy storage systems roadmap. However, this does not prevent the use of BESS connected 'behind the meter' at customers' premises from participating in the scheme – we consider that this forms part of the demand flexibility for the purposes of the ERS.

5.4. We considered additionality to be a key requirement to ensure that the ERS genuinely enhances the security and reliability of the power system and does not distort the operation of the wholesale market or other mechanisms already in place to help manage periods of tight supply. As we said in the Code amendment proposal consultation paper, these resources should already be participating in the wholesale electricity market at an earlier stage of a potential supply-demand imbalance, with strong market signals to make capacity available when shortfall conditions may give rise to a grid emergency.

5.5. To avoid the risk of a potential ERS provider exiting an existing market or mechanism in order to provide ERS, we included a 'look-back' period of 12 months – ie, a provider would not be eligible to provide ERS if they had, within the previous 12 months provided services:

(a) in the wholesale market (other than black start), or

(b) via a contract or other arrangement in circumstances that may correspond with a grid emergency.

5.6. We proposed to include the additionality criteria in the proposed new definition of emergency reserve in Part 1 of the Code. We also proposed an amendment to the definition of controllable load in Part 1 to exclude these resources from emergency reserve.

What submitters said

5.7. Submissions indicated support for the proposed eligibility criteria for emergency reserve, with submissions from EEA and Nova highlighting the importance of the additionality principle.

5.8. The main issue raised in submissions was the application of the 12-month look back provision to interruptible load providers.

Look-back period and interruptible load

5.9. Submissions from Enel X, MEUG and Transpower suggested that the proposed 12-month look back period should not apply to providers of interruptible load. This is because the entry of BESS into the instantaneous reserve ancillary service market is expected to push interruptible load out of the reserve market, because BESS is likely to be able to provide this service cheaper and faster. If there is a 12-month exclusion period to provide ERS, ex-interruptible load providers may completely exit the market. This means that consumers will no longer benefit from the contribution of these resources to system security.

Other issues

5.10. EEA's submission also proposed that the definition of emergency reserve should explicitly capture both aggregated demand-side resources and behind the meter generation or storage.

5.11. Nova's submission suggested additions to the Code to reinforce the additionality requirement, including:

(a) requiring mandatory disclosures from providers to the System Operator of any existing bilateral contracts; and

(b) specific drafting suggestions to further clarify the additionality test.

Our assessment

Look-back period and interruptible load

5.12. The Authority acknowledges the changing dynamics of the instantaneous reserves market with the entry of BESS. We agree that this warrants the exclusion of interruptible load from the 12-month look back period.

5.13. We have also considered whether there are circumstances in which the look back period may have the consequence of unduly excluding other potential providers and have concluded that it may. For example, a provider may enter a contract with a network operator to provide demand flexibility to defer network augmentation. When the contract comes to an end, the network operator may have progressed a network augmentation. In this situation, under our original proposals, the demand flexibility provider could no longer provide emergency reserve, even if they continued to have the interest and capability to do so. This would be notwithstanding that they were no longer able to provide demand flexibility to the network operator because of the network augmentation.

5.14. As a result, we also consider the 12-month look-back exclusion should not apply to providers who are no longer able to provide the previous service due to circumstances outside of their control. Providers wishing to take advantage of this exception will need to demonstrate to the System Operator that these circumstances apply.

Other issues

5.15. The Authority has reviewed its proposed definition of emergency reserve and considers that no amendments are needed to capture aggregated demand-side resources or behind the meter generation or storage. The existing definition is sufficient to ensure that these resources are eligible, subject to the additionality requirements, to provide emergency reserve.

5.16. We have not amended the Code to incorporate Nova's suggestions, as we consider that these are matters for the System Operator to consider in the development of the Procurement Plan.

Revised Code amendment

5.17. The Authority has amended the definition of emergency reserve in Part 1 to enable provision of the service in certain circumstances, even where the provider would have been excluded on the basis that they had provided a service in the wholesale electricity market or in response to another contract or arrangement in the previous 12 months. This exclusion will now not apply to:

(a) providers of interruptible load in the previous 12 months, provided that they are no longer offering this service; and

(b) other providers who are no longer able to provide the service due to circumstances outside of their control.

5.18. The definition of emergency reserve, including these changes, is as follows (blue text denotes the changes from the Code amendment proposal consultation paper):

emergency reserve means—

(a) an **ancillary service** that provides access to generation capacity or load that can be used to minimise the **electrical disconnection** of **demand** in a **grid emergency**, as specified in the **procurement plan**; but

(b) excludes any generating capacity or load that—

(i) otherwise provides services –

(A) in the **wholesale market** other than **black start**; or

(B) in response to a contract or other arrangement with a **purchaser** or **asset owner** in circumstances that may correspond with a **grid emergency**; or

(ii) has been used to provide the services referred to in paragraph (i) within the 12 months prior to being offered for use as **emergency reserve,** except for—

(A) load that has been used to provide **interruptible load** but is no longer being offered for use as **interruptible load**; or

(B) generating capacity or load that has been used to provide a service but where provision of the service ceased due to circumstances outside the **ancillary service agent's** control; or

(iii) is provided by an **energy storage system**, other than an **energy storage system** that is located on a **consumer's** premises for the purpose of reducing demand from the **grid**

Procurement

What we said

5.19. We proposed that the procurement trigger, process and service requirements would all be set out in the Procurement Plan and determined by the System Operator.

5.20. We proposed that the System Operator should procure emergency reserve up to four weeks ahead of an identified shortfall via a competitive tender process. We also considered the System Operator could establish a pre-approved panel of providers in advance of procurement, to streamline the procurement process in order to enable as wide a pool of potential providers as possible.

5.21. We also proposed a requirement, via proposed amendments to clause 8.54B of the Code, that a contracted emergency reserve provider must, where connected to a distribution network, advise the relevant distribution network operator that it has entered a contract for emergency reserve.

What submitters said

5.22. Submissions provided feedback on two elements of the procurement process – the timeframe for procurement and availability of the service and the trigger for procurement.

5.23. Submissions from Enel X, MEUG, Transpower and WEL Networks all indicated that uncertainty about the period for which the service is being provided – the 'availability period' – would result in providers being uncertain of their cost recovery. This would particularly be the case during the initial implementation of the scheme, since procurement within four weeks of an identified shortfall may also not provide adequate time for all parties to prepare to offer the service.

5.24. Submitters offered various suggestions for resolving this issue, including a specified or minimum availability period of up to 12 months.

5.25. Nova's submission recommended that the System Operator should:

(a) procure ERS on a locational basis, rather than nationally; and

(b) use probabilistic forecasting in determining the need for procuring ERS and the relevant quantity.

5.26. EEA's submission also noted the importance of clear and transparent activation triggers and thresholds.

Our assessment

Procurement and availability period

5.27. The Authority accepts that, particularly during the initial operation of the scheme, the intended procurement period of up to four weeks may not provide adequate time for parties to confirm their ability to provide the service and estimate the costs of doing so. We also accept that, in conjunction with a lack of certainty about the availability period (and associated cost recovery), this may discourage participation or potentially lead to higher priced offers if these factors are not appropriately managed.

5.28. We do not consider that a specified minimum 12-month availability period would be appropriate. While the ERS is available for use at any time during the year, it is not intended to be an 'any time' service. Providing for such a minimum available period may:

(a) increase the risk of distorting the operation of the wholesale electricity market;

(b) deter other arrangements to activate demand flexibility, which are intended to be used ahead of (and more frequently than) the ERS (eg, contracts with retailers to help manage peak demand periods); and

(c) deter some potential providers from participating in the ERS, if they are exposed to the risk of having to respond (eg, by reducing load) at any time in the year.

5.29. We are satisfied that it is not necessary to amend the proposed Code provisions to address these points. Instead, we note that the Code provisions already enable the System Operator to determine the appropriate availability period for an ERS procurement. We consider that it would be appropriate for the System Operator to consider a defined availability period for the early operation of the scheme (eg, three to six months), to provide greater certainty for both the operator and providers in determining the costs of the scheme during this period.

5.30. As experience is gained with the procurement of ERS, we expect that the availability period will be refined, to ensure consumers are only bearing the costs of the scheme during the periods of time it is most likely to be needed, and in a way that gives providers greater certainty regarding costs and costs recovery.

Procurement location and triggers

5.31. With regards to the location of procurement, we decided not to modify the proposed Code provisions. This is because the proposed Code provisions already enable the System Operator to determine where ERS resources may be required.

5.32. We note that the purpose of the ERS is to minimise the risk of uneconomic load shedding during capacity shortfalls. Such a shortfall could be national, or confined to one island or a region. In all cases, if emergency reserves are available in the relevant locations and in the time available, the System Operator should have the option of procuring and activating the relevant emergency reserve resources, without geographical limitations, to address the identified shortfall.

5.33. For example, if a shortfall is forecast in the North Island only, then the System Operator would seek to procure services capable of alleviating that shortfall. Whether a national or more location-specific procurement is required will be determined by the System Operator based on its forecasts of system reliability.

5.34. As we noted in our Code amendment proposal consultation paper, the Authority does not propose to specify how the System Operator should determine the quantum of emergency reserves to procure. This is a matter to be determined by the System Operator in accordance with the method to be set out in the Procurement Plan. We note that the System Operator is working on an ongoing basis to improve its forecasting methods and capability. We expect the most appropriate forecast approach to be used for the procurement of ERS both initially and into the future.

Activation

What we said

5.35. We proposed that the System Operator could activate emergency reserve in a grid emergency after the operation of all market and business-as-usual mechanisms (eg, contracted demand response and the use of EDB controllable load) and ahead of involuntary load curtailment.

5.36. After all business-as-usual mechanisms have operated, including the use of EDB controllable load resources, the System Operator should:

(a) pre-activate emergency reserve up to 36 hours ahead of real time; and

(b) activate emergency reserve up to one hour ahead of real time.

5.37. We proposed to include the activation of emergency reserve in the list of actions available to the System Operator in a grid emergency in clause 6 of Schedule 8.3 – Technical Code B of the Code. We also proposed supporting Code amendments:

(a) a new clause 5 in Schedule 8.3 – Technical Code B to require emergency reserve providers to respond to requests for information from the System Operator in a grid emergency; and

(b) new definitions of ‘activate’ and ‘pre-activate’ for emergency reserve in Part 1 of the Code.

5.38. The process for pre-activation would be determined by the System Operator and set out in the Procurement Plan and in contracts with ERS providers. The System Operator would also set out the trigger methodology for pre-activation and activation, the service requirements, the Procurement Plan and ERS contracts.

5.39. We also proposed that wholesale market prices should be maintained at the level they would have been (ie, scarcity prices) in the absence of the activation of emergency reserves. We proposed to amend clause 3 of Schedule 13.3AA to require the System Operator to ‘add back’ any demand reduction from the activation of ERS into the nodal load schedule to restore prices to the level they would have been without ERS.

What submitters said

5.40. Submissions provided some specific comments on elements of the activation process, including activation timeframes, the interaction of emergency reserve with other ancillary services and emergency response processes, and the mechanism to maintain wholesale market prices. These are outlined in the following sections.

5.41. EEA’s submission also highlighted the importance of ensuring the ERS remained a penultimate resort mechanism.

Activation timeframe

5.42. The submission from MEUG considered that activation of the service within a one-hour period may not provide sufficient time for some users to provide the response.

Interaction with other services and mechanisms

5.43. EEA's submission noted that the use of emergency reserve should be embedded within the broader system reliability framework. EEA also proposed that the Code be amended to require:

(a) coordination between Transpower and EDBs whenever emergency reserve is activated;

(b) compliance with the common load management protocol being developed by the Electricity Networks Aotearoa (ENA) Future Networks Forum;2 and

(c) information sharing between Transpower, EDBs and providers.

5.44. In its submission, EEA also proposed that clauses 8.43 to 8.45 of the Code should be clarified in order to align the ERS activation, measurement and verification requirements with those already in use for other ancillary services. EEA considered that doing so would reduce duplication, maintain technology neutrality and support efficient administration. EEA also suggested that telemetry and measurement protocols be aligned with the Electricity Information Exchange Protocol (EIEP) 14 modular data framework[3] and with existing ancillary services.

5.45. MEUG's submission also sought to clarify the relationship between emergency reserve and the deployment of participant rolling outage plans.[4]

Maintaining market prices

5.46. Transpower's submission noted that the proposed amendment to clause 3 in Schedule 13.3AA to maintain market prices may not be compatible with the implementation approach being considered by the System Operator. Transpower submitted that the approach should be agnostic as to the implementation approach and suggested alternative options.

Our assessment

Activation timeframe

5.47. We note the concern that some providers will need advance notification in order to be able to provide emergency reserves. However, rather than providing for this in the Code, we believe it is best addressed in the Procurement Plan.

5.48. Our design for the ERS includes a pre-activation step up to 36 hours ahead of anticipated use, which is intended to provide an opportunity for providers to commence preparations for providing the service.

5.49. The specific process for activation of emergency reserve will be set out in the Procurement Plan. We encourage providers to provide input into the development of this plan in the coming months.

2 Information on the ENA's working groups and forums is available on the ENA website.

3 The Authority recently consulted on a redesigned suite of EIEP14s to standardise the exchange of electricity product data.

4 The System Operator requires specified participants to develop participant rolling outage plans in accordance with clauses 9.6 to 9.13 of the Code.

Interaction with other services and mechanisms

5.50. We agree with EEA that coordination and the sharing of information between Transpower, EDBs and ERS providers will be essential for the use of emergency reserves and in a grid emergency more broadly. This issue was also raised in submissions to our earlier consultations on the ERS. However, we have decided not to change the proposed Code amendments to reflect these concerns due to existing provisions and expectations:

(a) New clause 5B in Schedule 8.3 – Technical Code B provides a specific obligation on ERS providers to provide information to the System Operator about their available emergency reserve when the System Operator expects that emergency reserve may be activated. This is to ensure the System Operator has complete and up to date information to be used in the activation of emergency reserve if required.

(b) As we noted in our Code amendment proposal consultation paper, the Code generally does not prescribe coordination mechanisms between the System Operator and EDBs. However, we expect that the System Operator and EDBs will make any necessary modifications to existing processes to support the implementation of the ERS. We consider that the System Operator, in consultation with relevant parties, is best placed to ensure that information is available and communicated to all relevant parties involved in the management of a grid emergency.

5.51. The Authority is also continuing to monitor the development of the proposed common load management protocol, which may support the effective coordination of resources connected to distribution networks.

5.52. We have not made any Code amendments to require the activation, measurement and verification requirements for the ERS to align with those already in use for other services. We expect the System Operator will leverage existing requirements where they are suitable for the ERS. However, there may be a need for the requirements for the ERS to be tailored, and the specific requirements will be developed by the System Operator as it develops the Procurement Plan content for the ERS in consultation with stakeholders.

5.53. The Authority expects there to be limited, if any, interaction between the new emergency reserve ancillary service and participant rolling outage plans. These services are designed for different types of emergency events:

(a) rolling outage plans relate to the coordination of planned outages in a longer-term energy shortage situation; and

(b) emergency reserves are intended to help manage a short-term capacity shortfall situation.

5.54. It is possible that a short-capacity shortfall may overlap with a longer-term energy shortage. However, such events are likely to be very rare, and their management by the System Operator will depend on their specific circumstances.

Maintaining market prices

5.55. We have made a further amendment to clause 3 of Schedule 13.3AA in response to Transpower's concerns. We do not intend to constrain how the System Operator implements the ERS, provided the outcome of maintaining wholesale market prices is achieved.

5.56. This further amendment seeks to give flexibility to the System Operator to determine how it will ensure wholesale market prices are maintained. This could involve adding back any ERS load reduction into the nodal load schedule, or another approach that has the same outcome for prices.

Revised Code amendment

5.57. We have amended clause 3 of Schedule 13.3AA to require the System Operator to maintain wholesale market prices at the level they would have been without any load reduction as a result of the activation of emergency reserve either by:

(a) adding the ERS load reduction back into the nodal load schedule (as per the Code consultation proposal); or

(b) using some other method determined by the System Operator (as discussed in sections 5.55 and 5.56 above and given effect by the new sub-clause (5) in clause 3 of Schedule 13.3AA).

5.58. The amended clause 3 in Schedule 13.3AA is as follows (red text denotes changes from the existing clause, and blue text denotes additional changes since the Code amendment proposal consultation paper):

Schedule 13.3AA - Managing an unsupplied demand situation in the dispatch schedule

3 Adjusting expected profile of demand for demand that was unable to be supplied

(1) As soon as practicable after the **system operator** instructs the **electrical disconnection** of **demand** in accordance with Schedule 8.3, Technical Code B, clause 6(1)(d) or 6(2)(d), or the **activation** of **emergency reserve** in accordance with Schedule 8.3, Technical Code B, clause (6)(1)(ca) or 6(2)(ca), the **system operator** must—

(a) calculate and record the **demand** limit for each relevant GXP; and

(b) record the Short-Term Load Forecast values for the relevant load forecast regions for all available 5-minute market intervals in the future, being the linear interpolation across time of the load forecast prepared under clause 13.7A.

(2) After the **system operator** has made an instruction ~~instructed the **electrical disconnection** of **demand**~~ under subclause (1), the expected profile of **demand** used in the **dispatch schedule**, for the purposes of calculating **dispatch prices**, is—

[…]

(4) The predicted demand referred to in subclause (3) is the amount of **demand** that was expected to be present at a given **conforming GXP** in interval 'i' absent the instruction ~~to **electrically disconnect demand**~~ referred to in subclause (1), estimated at the time of the instruction referred to in subclause (1), calculated as follows:

[…]

(5) Subclauses (1) to (3) do not apply in relation to the **activation** of **emergency reserve** if the **system operator** undertakes a different process that ensures that the **dispatch price** is not reduced as a result of the **activation** of **emergency reserve**.

Pricing and settlement

What we said

5.59. We proposed that ERS providers could recover both pre-event (ie, preparation and availability costs) and event fees (ie, pre-activation and activation costs). Providers could determine these fees on an individual basis in their contract with the System Operator.

5.60. We proposed that ERS costs should be recovered from purchasers on a national basis:

(a) pre-event costs would be allocated to loads based on their share of monthly metered consumption in relevant months; and

(b) event costs would be allocated to loads based on their metered consumption during activation events.

5.61. We proposed a new clause 8.58A of the Code, and supporting definitions in Part 1, to determine how emergency reserve costs would be recovered, including both pre-event costs and event costs.

5.62. We also proposed that the System Operator must make reasonable endeavours to ensure the anticipated costs of ERS are less than VoLL (on a per-unit basis). The System Operator would be expected to instruct regular load shedding if the anticipated costs of ERS were more than VoLL (on a per-unit basis).

What submitters said

5.63. Submitters indicated support for the proposed pricing and settlement Code amendments, including the allocation of ERS costs on a national basis.

5.64. Nova's submission raised a concern that providers may be able to receive multiple revenue streams from the same physical response. It also suggested amending the Code to net off any other payments for the same response to prevent any 'double dipping'.

5.65. Transpower's submission also suggested that, to facilitate the initial implementation of the scheme, an initial period cost recovery fund be established to support potential providers to commit early.

Our assessment

5.66. We note Nova's concern, but do not consider that a Code amendment is required to net off other payments. This is because of the requirement that the use of emergency reserves be additional to other responses, and only as a penultimate response after all 'business-as-usual' mechanisms. These design features ensure that where a provider has agreed to respond via any other contract or arrangement, they cannot also offer generating capacity or load for use as emergency reserve.

5.67. The Authority does not consider it necessary to consider establishing a separate funding mechanism to support the initial costs of provider. By providing more time for procurement and a more flexible availability period during the initial operation of the scheme (see section 5.27 above), along with more time for implementation (see section 6.4 below), providers and the System Operator should be better able to estimate the likely ERS payments and establish the cost recovery mechanism to recover costs from purchasers.

Performance management

What we said

5.68. We proposed that the performance of emergency reserve providers be managed proactively through procurement and pre-activation measures and, in the event of non-performance, via the forfeiture of payments. Pre-activation measures include due diligence by the System Operator as part of procurement, the ability to consider resource fatigue, the ability to ensure effectiveness, tailored communication processes, and pre-event testing of providers by the System Operator.

5.69. We proposed that the System Operator include proactive performance management measures, along with the performance requirements of the service and rules relating to the forfeiture of payment for non-performance, in the Procurement Plan and ERS contracts.

What submitters said

5.70. Submitters did not provide any comments on the Authority's proposed approach to performance management.

Information and publication

What we said

5.71. We proposed that the System Operator should publish:

(a) the forecasts on which it bases its decision to procure and activate emergency reserves;

(b) information to support the procurement of emergency reserves as part of the Procurement Plan and associated contract; and

(c) details of the use and expected cost of emergency reserves within 20 business days following any use of the service. We proposed a new clause 8.54BA of the Code to capture this proposed new requirement.

5.72. We also proposed that the Procurement Plan set out that:

(a) the System Operator's periodic reporting should include information about the procurement and use of emergency reserves; and

(b) the System Operator should provide the Authority with further details of the procurement and cost of emergency reserves.

What submitters said

5.73. EEA's submission proposed amendments to clause 8.54BA to:

(a) analyse network and consumer impacts;

(b) assess provider performance; and

(c) summarise operational lessons learnt.

5.74. EEA also suggested establishing an annual performance and learning report as well as an ERS implementation group to (among other things) evaluate ERS performance and consider future refinement of the scheme.

Our assessment

5.75. Ongoing transparency, monitoring and the identification of improvements are important for all elements of the electricity market, including emergency reserve.

5.76. The Authority notes that the new clause 8.54BA requires the System Operator to provide a report within 20 business days of a grid emergency. This report is intended to provide purchasers with information about the potential costs of any ERS procurement and activation. It is also intended to provide stakeholders more broadly with initial information about the procurement and use of emergency reserves shortly after an event.

5.77. Given the timing and purpose of this report, it is likely to be impractical to include additional information along the lines suggested by EEA. For these reasons we have decided not to modify the proposed Code amendments.

5.78. The Authority has also considered whether other reporting requirements should be strengthened. Having done so, we are satisfied that existing arrangements are already suitable and that no further Code amendments are required. These existing arrangements include the following expectations:

(a) The Authority will review the ERS at an appropriate point following its implementation and operation.

(b) The System Operator and Authority will undertake any necessary investigations after any grid emergency event as required and are also likely to report more broadly on the event, the impacts on the system and consumers, and any lessons learnt.

(c) The Procurement Plan will provide for further periodic reporting by the System Operator on the use of the ERS, whether or not a grid emergency has occurred.

5.79. We also consider that the Authority's existing mechanisms for monitoring the performance of market mechanisms and engaging with stakeholders are suitable for ongoing evaluation and consideration of potential improvements to the ERS over time.

5.80. At this stage, we do not propose to establish a new stakeholder group for this purpose. We consider the approach to engagement with stakeholders during the implementation of the ERS in sections 6.15 and 6.19 below.

Other Code amendments

5.81. We proposed a number of other Code amendments to enable the implementation of the ERS including:

(a) amendments to the definitions of allocable cost, ancillary services and bona fide physical reason in Part 1 to include emergency reserve;

(b) amendments to clause 7 of Schedule 8.3 – Technical Code B to ensure that emergency reserves (like interruptible loads) are excluded from the load available in the automatic under-frequency load shedding blocks; and

(c) exclusion of emergency reserve providers from the obligations on other ancillary service agents in clause 9 of Schedule 8.3 – Technical Code B to take independent action in response to extreme voltage or frequency levels.

What submitters said

5.82. The submission from MEUG was the only submission that commented on any of these matters. MEUG's submission also reiterated its concern (expressed in previous consultation on the ERS) that excluding load required to be reserved for automatic underfrequency load shedding (AUFLS) would reduce participation in the scheme by large users.

5.83. While not directly related to the Code amendments to establish an ERS, MEUG's submission also indicated its interest in continuing to engage with the Authority on our broader roadmap for demand flexibility, including the dispatchable demand mechanism.

5.84. Transpower's submission noted that the Authority is convening an expert co-design group for a proposed new standardised demand flexibility product, which, along with the ERS, was identified as an early action in the draft roadmap.

Our assessment

5.85. As we noted in our Code amendment proposal consultation paper, AUFLS is a mechanism designed to prevent system failure. While it might be desirable to activate as much demand response as possible ahead of involuntary load shedding, we do not consider it appropriate to do so at the expense of this important system security mechanism.

Further Code amendments identified by the Authority

5.86. As noted in section 2.5 above, we have also made the following changes, identified by the Authority following the release of our Code amendment proposal consultation paper:

(a) Included an inflation-adjusted VoLL in clause 4 of Schedule 12.2 of the Code for the purposes of the ERS, which is $35,305 per MWh as proposed in our previous consultation on the ERS.

(b) Amended Clause 8.54BA to require the System Operator to report the costs of the scheme against VoLL in its post-event reporting, which is important for demonstrating that the ERS is achieving the desired policy intent.

(c) Made minor amendments to the term $ERPOfftake_{PURxt}$ used in clause 8.58A, which sets out how emergency reserve costs are allocated, by adding the subscript "t" at the end of the defined term, for consistency with the term used in the calculation.

(d) Made other minor editorial changes to ensure consistency in punctuation style and bolding of defined terms (in clause 8.58A), hyphenation (in the definition of 'activate') and use of singular terms (in 8.54BA).

Revised Code amendments

5.87. The amendments referred to in paragraphs (a) to (c) above are shown below as follows:

(a) clauses 8.54BA and 8.58A, with blue text denotes changes from the Code amendment proposal consultation paper; and

(b) clause 4 of Schedule 12.2, with red text showing the changes from existing clause in the Code.

8.54BA Provision of information about the use of emergency reserve

The **system operator** must, within 20 **business days** of the conclusion of a **grid emergency** for which the **system operator** has procured or **activated emergency reserves**, **publish** a report containing:

(c) the total amount of **emergency reserve** procured in anticipation of the **grid emergency**;

(d) the total amounts of **emergency reserve** pre-activated or **activated** during the **grid emergency**;

(e) the estimated **emergency reserve pre-event cost** related to the **grid emergency** and the corresponding **emergency reserve pre-event trading periods**; ~~and~~

(f) the estimated **emergency reserve event cost** related to the **grid emergency** and the corresponding **emergency reserve event trading periods**~~.~~;

(g) the estimated **expected unserved energy** that was avoided by the **activation** of **emergency reserve**; and

(h) the estimated **value of expected unserved energy** that was avoided by the **activation** of **emergency reserve**.

8.58A Emergency reserve costs are allocated to purchasers

The **allocable cost** of **emergency reserve** must be paid by **purchasers** to the **system operator** in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula:

$$Share_{PURx} = \left[\frac{ERP_{ct} \times max(0, \Sigma_t ERPOfftake_{PURxt})}{\Sigma_x max(0, \Sigma_t ERPOfftake_{PURxt})}\right] + \left[\frac{ERE_{ct} \times max(0, \Sigma_t EREOfftake_{PURxt})}{\Sigma_x max(0, \Sigma_t EREOfftake_{PURxt})}\right]$$

where

$Share_{PURx}$ is **purchaser** x's share of **emergency reserve allocable costs**

ERP_{ct} is the **emergency reserve pre-event cost** in the **billing period**

$ERPOfftake_{PURxt}$ is the total **reconciled quantity** in kWh for **purchaser** x across all **grid exit points** in **emergency reserve pre-event trading periods** in the **billing period**

ERE_{ct} is the **emergency reserve event cost** in the **billing period**

$EREOfftake_{PURxt}$ is the total **reconciled quantity** in kWh for **purchaser** x across all **grid exit points** in **emergency reserve event trading periods** in **the billing period**.

Schedule 12.2 - Grid reliability standards

4 Value of expected unserved energy

(1) The value of any **expected unserved energy** is—

(a) $20,000 per **MWh**; or

(ab) $35,305 per **MWh** for the purpose of **emergency reserve**; or

(b) such other value, including for **emergency reserve**, as the **Authority** may determine.

6. Implementation

We have revised our target implementation date

6.1. In earlier consultations, the Authority proposed a target date of winter 2026 for implementation of the scheme. This target reflected the Authority's desire to have the ERS available as soon as practicable, noting that Transpower's Security of Supply Annual Assessment identified a risk to capacity margins from 2026 in the event thermal generation plant was unavailable.

6.2. Some submissions to our Code amendment proposal highlighted that it would be challenging to implement the ERS for winter 2026:

(a) Enel X's submission indicated the implementation timeframe was plausible, but it would require implementation activities to be done in parallel. Enel X also noted that a longer procurement and availability period during the initial operation of the scheme would help give providers confidence to participate in the scheme (see section 5.27 above).

(b) Transpower's submission raised significant concerns with implementation of the scheme by winter 2026. The process to develop the Procurement Plan was identified as a key reason for this. Transpower noted that an amendment to the Procurement Plan would usually take around 6 months, which may not leave sufficient time for procurement. Transpower's submission included some suggested approaches which could facilitate implementation of the ERS as quickly as possible. These are discussed in the next section.

6.3. The need for emergency reserve can happen at any time of year, not just during the winter period, because of unplanned limits on the availability of electricity supply sources or transmission infrastructure.

6.4. Recognising that implementation of the ERS by winter 2026 is challenging, the Authority has revised the target implementation date to fourth/last quarter of 2026 (Q4). The Authority will work with the System Operator and potential providers to progress implementation activities, as appropriate, to ensure that emergency reserves are available to support system security and reliability by Q4 2026, or earlier.

6.5. We have also considered how the approach to implementing the ERS can help ensure it is implemented as quickly as possible. This is discussed in the next section.

A pragmatic approach can support timely implementation

6.6. In our earlier consultations, the Authority considered that an MVP implementation would likely be required initially, to enable the scheme to be operational more quickly. The full implementation will come over time.

6.7. In its submission, Transpower notes that it has progressed work on developing a conceptual MVP that could meet the design principles of the ERS. Transpower the process to develop operational processes and systems will need to be undertaken relatively quickly. However, Transpower also identified the time required to develop the Procurement Plan as being particularly challenging.

6.8. Transpower's submission proposes several options that could facilitate timely implementation of the ERS, including:

(a) setting out the technical requirements for an initial ERS outside of the Procurement Plan, possibly as an appendix; and

(b) selecting a limited pool of providers with existing capability and experience to work with for the initial roll out, before opening for wider participation.[5]

6.9. Adjusting the target date for implementation will assist with the issues identified by submitters by providing more time for implementation of the scheme. However, to enable implementation as early as possible, the Authority considers that a pragmatic approach to the development of the Procurement Plan and initial procurement of the ERS will be required.

Development of the Procurement Plan

6.10. As noted in our Code amendment proposal consultation paper, the technical and operational details of the new emergency reserve ancillary service will be set out by the System Operator in the Procurement Plan. This is consistent with the approach for other ancillary services. WEL Network's submission noted that this approach would be pragmatic but would mean that it will not be possible to comment on the elements of the ERS arrangements until the Procurement Plan is available.

6.11. The Authority notes that the Procurement Plan will provide the legal basis for the procurement of emergency reserve. While the Code enables the System Operator to procure the service, the System Operator also needs to act in accordance with the Procurement Plan. As a result, the System Operator needs to formalise all necessary content to determine the trigger for and technical requirements of the service before starting to procure the service.

6.12. In response to the issues and suggestions raised by Transpower, we have considered whether regulatory support could be provided for the development of the initial Procurement Plan requirements for the ERS, in the form of a regulatory sandbox or similar transitional provisions.

6.13. Any such support would need to be developed to suit the specific circumstances of the implementation of the ERS, with no 'template' available. As a result, it is unlikely

5 Other options identified by Transpower, such as making availability payments available for a defined period, have already been discussed in section 5 of this decision paper.

that such an approach would provide a sufficiently timely mechanism to simplify the process for setting out the Procurement Plan contents.

6.14. We also consider that it should be possible to develop the Procurement Plan content for the ERS, in consultation with stakeholders, in the time available for a Q4 2026 implementation. This could include development of a separate part of the Procurement Plan, to avoid the need to integrate emergency reserve into the existing plan's structure if this offered a faster approach.

6.15. The Authority encourages the System Operator to engage with potential providers from the outset to co-design the Procurement Plan contents. We consider that a working group or series of workshops, led by the System Operator and with the Authority as an observer, could be an effective approach.[6] This approach should enable timely finalisation of the Procurement Plan by the System Operator and the Authority.

Initial participation in emergency reserves

6.16. Transpower's submission suggested that commencing with a limited pool of providers, with capability and experience in providing similar services, could also support a timelier implementation of the ERS.

6.17. MEUG's submission noted that its members may not wish to offer to provide ERS initially, preferring to monitor the initial operation of the scheme and the prices paid.[7]

6.18. Overall, the net benefits of the ERS will be highest when the widest potential pool of providers is able to participate in the scheme. However, we recognise that for the initial implementation of the scheme, it may be prudent to commence with a more limited pool of providers. This could help ensure the scheme operates as intended from the outset and allow both the System Operator and potential providers the opportunity to developed foundational knowledge about the service which can be built upon over time.

6.19. The Authority considers that the co-design process proposed in the previous section could also be used to identify potential providers that may have the capability to provide emergency reserves when it is first procured. Over time, as all parties gain more experience with the scheme, participation should be encouraged by other eligible providers where they have the interest and technical capability to provide emergency reserves.

6 As noted in section 5.74, EEA's submission also proposed the establishment of an implementation group.

7 MEUG's submission also noted that, as the ERS is expected to be used infrequently, it may not offer sufficient value for participation by some potential providers.

7. We consider our approach, as amended, is preferable to alternatives

7.1. In our Code amendment proposal consultation paper, we included the results of a cost benefit assessment (CBA) undertaken by Concept Consulting (Concept) for the proposed ERS. This assessment concluded that the proposed ERS would deliver a net benefit to New Zealand electricity consumers by improving the reliability of New Zealand's electricity supply and reducing the likelihood and quantity of involuntary uneconomic load shedding.

The ERS could deliver benefits of $21 million over a 20-year period

7.2. Concept's assessment was that the proposed Code amendments to establish an ERS would deliver quantifiable benefits of $21 million over a 20-year period. In addition, Concept advised that the scheme would likely deliver substantial non-quantifiable benefits that may exceed the quantifiable benefits. These unquantifiable benefits included:

(a) avoided impacts (costs) on consumers from the unavailability of their electricity supply during an emergency event (eg, inconvenience, triggering the purchase of back-up generation and possible risks to health and safety);

(b) avoided costs to the System Operator, EDBs and others of managing involuntary load shedding, including communications with consumers;

(c) avoided costs to the System Operator, regulatory authorities and government of post-event reviews and other actions triggered as a result of involuntary load shedding; and

(d) avoided costs of any impact on consumers' confidence in the electricity system and reputational damage to New Zealand as a destination for tourism or investment.

7.3. Concept considered two alternative options to the proposed amendment – the status quo, and investment in additional flexible supply to avoid the level of involuntary load shedding expected to be met using the proposed ERS. Concept considered that an ERS is expected to deliver a higher net benefit when compared to both of these alternatives.

What submitters said

7.4. Submissions from EEA, Enel X and WEL Networks supported the CBA's findings and agreed that the benefits of the ERS would outweigh its costs. Transpower's submission noted that the extent of any benefits would be sensitive to the number of times the ERS is activated to minimise the likelihood and extent of involuntary load shedding. Other submissions did not specifically comment on this.

7.5. Submissions from EEA, Enel X, Transpower and WEL Networks also considered that the ERS was preferable to other options, in particular, an interventional investment in additional supply capacity.

7.6. EEA's submission considered that Concept's assessment may understate the overall benefits of the scheme, once broader resilience and consumer confidence benefits were considered. EAA also noted further unquantifiable benefits of the ERS, including that the operation of the ERS supports capability building by participants and broader system learning.

Our assessment

7.7. Feedback from submissions confirms the Authority's view that the ERS is expected to deliver an overall benefit to consumers and is preferable to other options. For more details see section 7 of the Code amendment proposal consultation paper.

8. Our decision supports our statutory objectives

8.1. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. We consider that both the primary and secondary objectives are relevant to the Code amendments to establish an ERS.

8.2. Section 32(1) of the Act says that the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

8.3. The Authority considers that the proposed amendment falls within the above sections of the Act in that it is necessary or desirable to promote the efficient operation of the electricity industry and protect the interests of domestic and small business consumers of electricity for the reasons set out in sections 7.14 to 7.18 of our Code amendment proposal consultation paper.

8.4. The findings of Concept's CBA, which we included at Appendix B of our Code amendment proposal consultation paper, also supported this assessment. This CBA included consideration of alternative options to address the issue identified (the risk of uneconomic load shedding).

8.5. Submissions from EEA, Enel X, Transpower and WEL Networks considered that the proposed Code amendments to establish the ERS satisfied the requirements of section 32(1) of the Act, including that the amendments are consistent with our statutory objective. No submissions indicated a different view.

8.6. The Authority also considers that the proposed amendment provides an overall net benefit for New Zealand electricity consumers, for the reasons outlined in sections 7.3 to 7.10 of our Code amendment proposal consultation paper. As noted in section 7.4 above, submitters endorsed this assessment.

9. Next steps

9.1. The Code amendments to establish the emergency reserve ancillary service will come into force on 1 March 2026.

9.2. The System Operator and Clearing Manager will undertake the necessary steps to implement the ERS by Q4 2026. This will include:

(a) development of the Procurement Plan and associated documents (eg, contract templates) for emergency reserves;

(b) establishment of internal processes for the procurement, activation and reporting of emergency reserve; and

(c) any necessary system changes to facilitate the procurement and activation of emergency reserve or recovery of emergency reserve costs.

9.3. Based on the identified need for the service, the System Operator would then commence procurement of the emergency reserve ancillary service.

10. Attachments

10.1. The following appendices are attached to this paper:

Appendix A Code amendment

Appendix B Code amendment (tracked changes)

Appendix A Code amendment

Appendix A: Code amendment

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

activate, for the purpose of **emergency reserve**, means the process of issuing instructions and notifications to providers of **emergency reserve** for the use of **emergency reserve** in real time, as specified in the **procurement plan**

allocable cost has the meaning set out in clauses 8.55 to 8.58A

ancillary service means **black start**, **emergency reserve**, **over frequency reserve**, **frequency keeping**, **instantaneous reserve** or **voltage support**

bona fide physical reason includes,—

[…]

(bb) in relation to an **ancillary service agent** providing **emergency reserve**,—

  (i) a reasonably unforeseeable full or partial loss of demand or reserve capability (as the case may be) that is the subject of an **ancillary service arrangement** to provide **emergency reserve**; or

  (ii) a reasonably unforeseeable full or partial loss of generating capability from an item of **generating plant** that is the subject of an **ancillary service arrangement** to provide **emergency reserve**; or

  (iii) a reasonably unforeseeable change in circumstances such that the **ancillary service agent** will breach any consent held by it under the Resource Management Act 1991; and

[…]

controllable load, for the purposes of Part 8, means the quantity of resources (in **MW**) that a **connected asset owner** estimates will be available for use by the **system operator** under a **grid emergency**. The available **controllable load** must exclude—

(a) resources a **connected asset owner** intends to use for its own network demand management purposes; and

(b) any resources offered into the **instantaneous reserves** market; and

(c) any resources bid or offered on behalf of a **dispatch-capable load station** or **dispatch notification purchaser** or **dispatch notification generator**; and

(d) any contracted **emergency reserve**

<u>**emergency reserve** means—</u>

<u>(a) an **ancillary service** that provides access to generation capacity or load that can be used to minimise the **electrical disconnection** of **demand** in a **grid emergency**, as specified in the **procurement plan**; but</u>

<u>(b) excludes any generating capacity or load that—</u>

(i) otherwise provides services, or has been used to provide such services within the 12 months prior to being offered for use as **emergency reserve—**
   (A) in the **wholesale market** other than **black start**; or
   (B) in response to a contract or other arrangement with a **purchaser** or **asset owner** in circumstances that may correspond with a **grid emergency**; or

(ii) has been used to provide the services referred to in paragraph (i) within the 12 months prior to being offered for use as **emergency reserve,** except for**—**
   (A) load that has been used to provide **interruptible load** but is no longer being offered for use as **interruptible load**; or
   (B) generating capacity or load that has been used to provide a service but where provision of the service ceased due to circumstances outside the **ancillary service agent's** control; or

(iii) is provided by an **energy storage system**, other than an **energy storage system** that is located on a **consumer's** premises for the purpose of reducing demand from the **grid**

emergency reserve event is an event involving the **pre-activation** or **activation** of **emergency reserve** in a **grid emergency,** or when a **grid emergency** is reasonably foreseeable by the **system operator**, in accordance with an **emergency reserve** contract and as specified in the **procurement plan**

emergency reserve event cost means the total costs payable under **emergency reserve** contracts relating to an **emergency reserve event** within a **billing period**

emergency reserve event trading period means the relevant **trading period** or periods in which an **emergency reserve event** occurs

emergency reserve pre-event cost means the total amount of pre-event costs payable under **emergency reserve** contracts within a **billing period**

emergency reserve pre-event trading period means the relevant **trading period** or periods in which the **system operator** determines that **emergency reserve** must be available, as specified in the **procurement plan** or **emergency reserve** contract

expected unserved energy means a forecast of the aggregate amount by which **demand** for **electricity** exceeds the **supply** of **electricity** at each **grid exit point** as a result of—

(a) likely planned or unplanned outages of **primary transmission equipment**; or

(b) a **grid emergency**

pre-activate, for the purposes of **emergency reserve**, means the process of issuing instructions and notifications to providers of **emergency reserve** to prepare for the use of **emergency reserve**, as specified in the **procurement plan**

Subpart 4—Interruptible load and emergency reserve

8.54A Contents of this subpart

This subpart provides for the provision of information relating to **interruptible load** and **emergency reserve**.

8.54B Ancillary service agents to provide information about interruptible load and emergency reserve

(1) Each **ancillary service agent** that contracts for **interruptible load** or **emergency reserve** in a **network** must, within 10 **business days** of entering into the contract, give the following **participants** the information in subclause (2):

- (a) if the **interruptible load** or **emergency reserve** is contracted on a **local network**, the **connected asset owner** that operates the **local network**:
- (b if the **interruptible load** or **emergency reserve** is contracted on an **embedded network**, the **connected asset owner** that operates the **local network** to which the **embedded network** is connected:
- (c) if the **interruptible load** or **emergency reserve** is contracted on the **grid**, the **grid owner** that owns or operates the part of the **grid** on which the **interruptible load** or **emergency reserve** is contracted.

(2) The information required is—

- (a) a list of the **ICPs** to which the contract relates; and
- (b) the maximum **MW** that can be **activated** or interrupted under the contract; and
- (c) the commencement and expiry dates of the contract.

(3) If an **ancillary service agent** has given a **connected asset owner** or **grid owner** information under subclause (1), the **connected asset owner** or **grid owner** may require the **ancillary service agent** to provide further information about the **interruptible load** or **emergency reserve** to which the contract relates.

(4) An **ancillary service agent** must comply with a requirement under subclause (3).

8.54BA Provision of information about the use of emergency reserve

The **system operator** must, within 20 **business days** of the conclusion of a **grid emergency** for which the **system operator** has procured or **activated emergency reserve**, **publish** a report containing:

(a) the total amount of **emergency reserve** procured in anticipation of the **grid emergency**;

(b) the total amounts of **emergency reserve pre-activated** or **activated** during the **grid emergency**;

(c) the estimated **emergency reserve pre-event cost** related to the **grid emergency** and the corresponding **emergency reserve pre-event trading periods**;

(d) the estimated **emergency reserve event cost** related to the **grid emergency** and the corresponding **emergency reserve event trading periods**~~.~~;

(e) the estimated **expected unserved energy** that was avoided by the **activation** of **emergency reserve**; and

(f) the estimated **value of expected unserved energy** that was avoided by the **activation** of **emergency reserve**.

8.58A Emergency reserve costs are allocated to purchasers

The **allocable cost** of **emergency reserve** must be paid by **purchasers** to the **system operator** in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula:

$$\boldsymbol{Share_{PURx}} = \left[\frac{\boldsymbol{ERP_{ct} \times max(0, \Sigma_t ERPOfftake_{PURxt})}}{\boldsymbol{\Sigma_x max(0, \Sigma_t\, ERPOfftake_{PURxt}}}\right] + \left[\frac{\boldsymbol{ERE_{ct} \times max(0, \Sigma_t EREOfftake_{PURxt})}}{\boldsymbol{\Sigma_x\, max(0, \Sigma_t EREOfftake_{PURxt})}}\right]$$

where

$Share_{PURx}$	is **purchaser** x's share of **emergency reserve allocable costs**
ERP_{ct}	is the **emergency reserve pre-event cost** in the **billing period**
$ERPOfftake_{PURxt}$	is the total **reconciled quantity** in **kWh** for **purchaser** x across all **grid exit points** in **emergency reserve pre-event trading periods** in the **billing period**~~.~~
ERE_{ct}	is the **emergency reserve event cost** in the **billing period**
$EREOfftake_{PURxt}$	is the total **reconciled quantity** in **kWh** for **purchaser** x across all **grid exit points** in **emergency reserve event trading periods** in the **billing period**.

Schedule 8.3
Technical codes

Technical Code B – Emergencies

5B An **ancillary service agent** must, as soon as reasonably practicable following a request by the **system operator**, inform the **system operator** of its available **emergency reserve** using a method or form agreed with the **system operator**.

6 Actions to be taken by the system operator in a grid emergency

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

- (a) request that a **generator** varies its **offer** and **dispatch** the **generator** in accordance with that **offer**, to ensure there is sufficient generation and **frequency keeping**:
- (b) request that a **purchaser** or a **connected asset owner** reduce **demand**:
- (c) require a **grid owner** to reconfigure the **grid**:
- (ca) **activate emergency reserve**:
- (d) require the **electrical disconnection** of **demand** in accordance with clause 7(20):
- (e) take any other reasonable action to alleviate the **grid emergency**.

(2) If insufficient transmission capacity gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:

- (a) request that a **generator** varies its **offer** and **dispatch** the **generator** in accordance with that **offer**, to ensure that the available transmission capacity within the **grid** is sufficient to transmit the remaining level of **demand**:
- (b) request that an **asset owner** restores its **assets** that are not in service:
- (c) request that a **purchaser** or **connected asset owner** reduces its **demand**:
- (ca) **activate emergency reserve**:
- (d) require the **electrical disconnection** of **demand** in accordance with clause 7(20):
- (e) take any other reasonable action to alleviate the **grid emergency**.

(3) If frequency is outside the **normal band** and all available **injection** has been **dispatched**, the **system operator** may require the **electrical disconnection** of **demand** in accordance with clause 7(20) in appropriate block sizes until frequency is restored to the **normal band**.

(4) If any **grid** voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1), and is sustained at or below that limit, the **system operator** may require the **electrical disconnection** of **demand** in accordance with clause 7(20) in appropriate block sizes until the voltage is restored to above the minimum voltage limit.

(5) The **system operator** may, if an unexpected event occurs giving rise to a **grid emergency**, take any reasonable action to alleviate the **grid emergency**.

7 Load shedding systems

[…]

(7) To avoid doubt, the **demand** calculated to comprise **automatic under-frequency load shedding** blocks must be net of any **interruptible load** or **emergency reserve** procured by the **system operator**.

[…]

(17) The **system operator**, each **connected asset owner**, each **grid owner** and each relevant **retailer** must, to the extent reasonably practicable, co-operate to ensure that any **interruptible load** or **emergency reserve** contracted by the **system operator** that could affect the size of an **automatic under-frequency load shedding** block is identified to assist the **connected asset owner** or the **grid owner** to meet its obligations in subclauses (1) to (9).

[…]

9 Obligations of generators and ancillary service agents to take independent action

<u>(1)</u> The following independent action is required of **generators** and **ancillary service agents** during the occurrence of extreme variations of frequency or voltage at the **points of connection** to which their **assets** are connected (such extreme levels of frequency or voltage are deemed to constitute a **grid emergency** and require a fast and independent response from each **generator** and each **ancillary service agent**):

[…]

(2) For the purpose of subclause (1), **ancillary service agent** does not include a person in respect of that person's provision of **emergency reserve**.

Schedule 12.2

Grid reliability standards

4 Value of expected unserved energy

(1) The value of any **expected unserved energy** is—

(a) $20,000 per **MWh**; or

(ab) $35,305 per **MWh** for the purpose of **emergency reserve**; or

(b) such other value, including for **emergency reserve**, as the **Authority** may determine.

[…]

Schedule 13.3AA
Managing an unsupplied demand situation in the dispatch schedule

3 Adjusting expected profile of demand for demand that was unable to be supplied

(1) As soon as practicable after the **system operator** instructs the **electrical disconnection** of **demand** in accordance with Schedule 8.3, Technical Code B, clause 6(1)(d) or 6(2)(d), or the **activation** of **emergency reserve** in accordance with Schedule 8.3, Technical Code B, clause (6)(1)(ca) or 6(2)(ca), the **system operator** must—

(a) calculate and record the **demand** limit for each relevant GXP; and

(b) record the Short-Term Load Forecast values for the relevant load forecast regions for all available 5-minute market intervals in the future, being the linear interpolation across time of the load forecast prepared under clause 13.7A.

(2) After the **system operator** has made an instruction under subclause (1), the expected profile of **demand** used in the **dispatch schedule**, for the purposes of calculating **dispatch prices**, is—

[…]

(4) The predicted demand referred to in subclause (3) is the amount of **demand** that was expected to be present at a given **conforming GXP** in interval ‘i’ absent the instruction referred to in subclause (1), estimated at the time of the instruction referred to in subclause (1), calculated as follows:

[…]

(5) Subclauses (1) to (3) do not apply in relation to the **activation** of **emergency reserve** if the **system operator** undertakes a different process that ensures that the **dispatch price** is not reduced as a result of the **activation** of **emergency reserve**.

Appendix B Code amendment (tracked changes)

Appendix B: Code amendment

Red underlined text indicates additions from the current Code.

~~Red strikethrough~~ text indicates deletions from the current Code.

Highlighted text indicates changes to red text in the version previously consulted on.

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

activate, for the purpose of **emergency reserve**, means the process of issuing instructions and notifications to providers of **emergency reserve** for the use of **emergency reserve** in ~~real-time~~ real time, as specified in the **procurement plan**

allocable cost has the meaning set out in clauses 8.55 to 8.58A

ancillary service means **black start**, **emergency reserve**, **over frequency reserve**, **frequency keeping**, **instantaneous reserve** or **voltage support**

bona fide physical reason includes,—

[…]

(bb) in relation to an **ancillary service agent** providing **emergency reserve**,—

(i) a reasonably unforeseeable full or partial loss of demand or reserve capability (as the case may be) that is the subject of an **ancillary service arrangement** to provide **emergency reserve**; or

(ii) a reasonably unforeseeable full or partial loss of generating capability from an item of **generating plant** that is the subject of an **ancillary service arrangement** to provide **emergency reserve**; or

(iii) a reasonably unforeseeable change in circumstances such that the **ancillary service agent** will breach any consent held by it under the Resource Management Act 1991; and

[…]

controllable load, for the purposes of Part 8, means the quantity of resources (in **MW**) that a **connected asset owner** estimates will be available for use by the **system operator** under a **grid emergency**. The available **controllable load** must exclude—

(a) resources a **connected asset owner** intends to use for its own network demand management purposes; and

(b) any resources offered into the **instantaneous reserves** market; and

(c) any resources bid or offered on behalf of a **dispatch-capable load station** or **dispatch notification purchaser** or **dispatch notification generator**; and

(d) any contracted **emergency reserve**

emergency reserve means—

(a) an **ancillary service** that provides access to generation capacity or load that can be used to minimise the **electrical disconnection** of **demand** in a **grid emergency**, as specified in the **procurement plan**; but

(b) excludes any generating capacity or load that—

  (i) otherwise provides services, or has been used to provide such services within the 12 months prior to being offered for use as **emergency reserve**—

    (A) in the **wholesale market** other than **black start**; or

    (B) in response to a contract or other arrangement with a **purchaser** or **asset owner** in circumstances that may correspond with a **grid emergency**; or

  (ii) has been used to provide the services referred to in paragraph (i) within the 12 months prior to being offered for use as **emergency reserve,** except for—

    (A) load that has been used to provide **interruptible load** but is no longer being offered for use as **interruptible load**; or

    (B) generating capacity or load that has been used to provide a service but where provision of the service ceased due to circumstances outside the **ancillary service agent's** control; or

  (iii) is provided by an **energy storage system**, other than an **energy storage system** that is located on a **consumer's** premises for the purpose of reducing demand from the **grid**

emergency reserve event is an event involving the **pre-activation** or **activation** of **emergency reserve** in a **grid emergency,** or when a **grid emergency** is reasonably foreseeable by the **system operator**, in accordance with an **emergency reserve** contract and as specified in the **procurement plan**

emergency reserve event cost means the total costs payable under **emergency reserve** contracts relating to an **emergency reserve event** within a **billing period**

emergency reserve event trading period means the relevant **trading period** or periods in which an **emergency reserve event** occurs

emergency reserve pre-event cost means the total amount of pre-event costs payable under **emergency reserve** contracts within a **billing period**

emergency reserve pre-event trading period means the relevant **trading period** or periods in which the **system operator** determines that **emergency reserve** must be available, as specified in the **procurement plan** or **emergency reserve** contract

~~**emergency reserve event trading period** means the relevant **trading period** or periods in which an **emergency reserve event** occurs~~

expected unserved energy means a forecast of the aggregate amount by which **demand** for **electricity** exceeds the **supply** of **electricity** at each **grid exit point** as a result of—

(a) likely planned or unplanned outages of **primary transmission equipment**; or

(b) a **grid emergency**

pre-activate, for the purposes of **emergency reserve**, means the process of issuing instructions and notifications to providers of **emergency reserve** to prepare for the use of **emergency reserve**, as specified in the **procurement plan**

Subpart 4—Interruptible load and emergency reserve

8.54A Contents of this subpart

This subpart provides for the provision of information relating to **interruptible load** and **emergency reserve**.

8.54B Ancillary service agents to provide information about interruptible load and emergency reserve

(1) Each **ancillary service agent** that contracts for **interruptible load** or **emergency reserve** in a **network** must, within 10 **business days** of entering into the contract, give the following **participants** the information in subclause (2):

(a) if the **interruptible load** or **emergency reserve** is contracted on a **local network**, the **connected asset owner** that operates the **local network**:

(b if the **interruptible load** or **emergency reserve** is contracted on an **embedded network**, the **connected asset owner** that operates the **local network** to which the **embedded network** is connected:

(c) if the **interruptible load** or **emergency reserve** is contracted on the **grid**, the **grid owner** that owns or operates the part of the **grid** on which the **interruptible load** or **emergency reserve** is contracted.

(2) The information required is—

(a) a list of the **ICPs** to which the contract relates; and

(b) the maximum **MW** that can be **activated** or interrupted under the contract; and

(c) the commencement and expiry dates of the contract.

(3) If an **ancillary service agent** has given a **connected asset owner** or **grid owner** information under subclause (1), the **connected asset owner** or **grid owner** may require the **ancillary service agent** to provide further information

about the **interruptible load** or **emergency reserve** to which the contract relates.

(4) An **ancillary service agent** must comply with a requirement under subclause (3).

8.54BA Provision of information about the use of emergency reserve

The **system operator** must, within 20 **business days** of the conclusion of a **grid emergency** for which the **system operator** has procured or **activated emergency reserves**, **publish** a report containing:

(a) the total amount of **emergency reserve** procured in anticipation of the **grid emergency**;

(b) the total amounts of **emergency reserve pre-activated** or **activated** during the **grid emergency**;

(c) the estimated **emergency reserve pre-event cost** related to the **grid emergency** and the corresponding **emergency reserve pre-event trading periods**; ~~and~~

(d) the estimated **emergency reserve event cost** related to the **grid emergency** and the corresponding **emergency reserve event trading periods**~~.~~;

(e) the estimated **expected unserved energy** that was avoided by the **activation** of **emergency reserve**; and

(f) the estimated **value of expected unserved energy** that was avoided by the **activation** of **emergency reserve**.

8.58A Emergency reserve costs are allocated to purchasers

The **allocable cost** of **emergency reserve** must be paid by **purchasers** to the **system operator** in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula:

$$Share_{PURx} = \left[\frac{ERP_{ct} \times max(0, \Sigma_t ERPOfftake_{PURxt})}{\Sigma_x max(0, \Sigma_t\, ERPOfftake_{PURxt}}\right] + \left[\frac{ERE_{ct} \times max(0, \Sigma_t EREOfftake_{PURxt})}{\Sigma_x\, max(0, \Sigma_t EREOfftake_{PURxt})}\right]$$

where

$Share_{PURx}$ is **purchaser** x's share of **emergency reserve allocable costs**~~.~~

ERP_{ct} is the **emergency reserve pre-event cost** in the **billing period**

$ERPOfftake_{PURxt}$ is the total **reconciled quantity** in **kWh** for **purchaser** x across all **grid exit points** in **emergency reserve pre-event trading periods** in the **billing period**~~.~~

ERE_{ct} is the **emergency reserve event cost** in the **billing period**.

$EREOfftake_{PURxt}$ is the total **reconciled quantity** in **kWh** for **purchaser** x across all **grid exit points** in **emergency reserve event trading periods** in the **billing period**.

Schedule 8.3
Technical codes

Technical Code B – Emergencies

5B An **ancillary service agent** must, as soon as reasonably practicable following a request by the **system operator**, inform the **system operator** of its available **emergency reserve** using a method or form agreed with the **system operator**.

6 Actions to be taken by the system operator in a grid emergency

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

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

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

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

(ca) **activate emergency reserve**:

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

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

(2) If insufficient transmission capacity gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:

(a) request that a **generator** varies its **offer** and **dispatch** the **generator** in accordance with that **offer**, to ensure that the available transmission capacity within the **grid** is sufficient to transmit the remaining level of **demand**:

(b) request that an **asset owner** restores its **assets** that are not in service:

(c) request that a **purchaser** or **connected asset owner** reduces its **demand**:

(ca) **activate emergency reserve**:

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

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

(3) If frequency is outside the **normal band** and all available **injection** has been **dispatched**, the **system operator** may require the **electrical disconnection** of **demand** in accordance with clause 7(20) in appropriate block sizes until frequency is restored to the **normal band**.

(4) If any **grid** voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1), and is sustained at or below that limit, the **system operator** may require the **electrical disconnection** of **demand** in accordance with clause 7(20) in appropriate block sizes until the voltage is restored to above the minimum voltage limit.

(5) The **system operator** may, if an unexpected event occurs giving rise to a **grid emergency**, take any reasonable action to alleviate the **grid emergency**.

7 Load shedding systems

[…]

(7) To avoid doubt, the **demand** calculated to comprise **automatic under-frequency load shedding** blocks must be net of any **interruptible load** or **emergency reserve** procured by the **system operator**.

[…]

(17) The **system operator**, each **connected asset owner**, each **grid owner** and each relevant **retailer** must, to the extent reasonably practicable, co-operate to ensure that any **interruptible load** or **emergency reserve** contracted by the **system operator** that could affect the size of an **automatic under-frequency load shedding** block is identified to assist the **connected asset owner** or the **grid owner** to meet its obligations in subclauses (1) to (9).

[…]

9 Obligations of generators and ancillary service agents to take independent action

(1) The following independent action is required of **generators** and **ancillary service agents** during the occurrence of extreme variations of frequency or voltage at the **points of connection** to which their **assets** are connected (such extreme levels of frequency or voltage are deemed to constitute a **grid emergency** and require a fast and

independent response from each **generator** and each **ancillary service agent**):

[…]

(2) For the purpose of subclause (1), **ancillary service agent** does not include a person in respect of that person's provision of **emergency reserve**.

Schedule 12.2
Grid reliability standards

4 Value of expected unserved energy

(1) The value of any **expected unserved energy** is—

(a) $20,000 per **MWh**; or

(ab) $35,305 per **MWh** for the purpose of **emergency reserve**; or

(b) such other value, including for **emergency reserve**, as the **Authority** may determine.

[…]

Schedule 13.3AA
Managing an unsupplied demand situation in the dispatch schedule

3 Adjusting expected profile of demand for demand that was unable to be supplied

(1) As soon as practicable after the **system operator** instructs the **electrical disconnection** of **demand** in accordance with Schedule 8.3, Technical Code B, clause 6(1)(d) or 6(2)(d), or the **activation** of **emergency reserve** in accordance with Schedule 8.3, Technical Code B, clause (6)(1)(ca) or 6(2)(ca), the **system operator** must—

(a) calculate and record the **demand** limit for each relevant GXP; and

(b) record the Short-Term Load Forecast values for the relevant load forecast regions for all available 5-minute market intervals in the future, being the linear interpolation across time of the load forecast prepared under clause 13.7A.

(2) After the **system operator** has made an instruction ~~instructed the **electrical disconnection** of **demand**~~ under subclause (1), the expected profile of **demand** used in the **dispatch schedule**, for the purposes of calculating **dispatch prices**, is—

[…]

(4) The predicted demand referred to in subclause (3) is the amount of **demand** that was expected to be present at a given **conforming GXP** in interval 'i' absent the instruction ~~to **electrically disconnect demand**~~ referred to in subclause (1), estimated at the time of the instruction referred to in subclause (1), calculated as follows:

[…]

(5) Subclauses (1) to (3) do not apply in relation to the **activation** of **emergency reserve** if the **system operator** undertakes a different process that ensures that the **dispatch price** is not reduced as a result of the **activation** of **emergency reserve**.