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Establishing an Emergency Reserve Scheme

Transpower welcomes the Authority's consultation *Establishing an Emergency Reserve Scheme* published 31 July. This submission is from Transpower in its role as System Operator.

We support the Authority's consideration of an Emergency Reserve Scheme (ERS) as a penultimate resort mechanism for securing the system at times of potential shortfall in generation capacity. As was the case on the 9th of August 2021, a confluence of unanticipated events on the system can result in a lack of generation in real-time. An ERS could mitigate potential impacts of such an event on consumers who otherwise may face involuntary load management to stabilise and balance the system and help to avoid further loss of supply.

As the Authority describes, such a scheme would effectively be an insurance policy for consumers to shield them from the worst effects of a generation shortfall — the corollary being the scheme must present a positive balance of benefits to the costs of its implementation and maintenance. To be beneficial the scheme should leverage opportunities to either replace centrally dispatched generation with lower cost alternative energy sources that would not otherwise have been made available during an event, or shift demand away from higher cost peak demand periods. The decision to proceed to implement any ERS should also consider changes since 9th August, particularly investment in grid-scale batteries and retailers contracting for industrial demand response.

The Robinson Bowmaker Paul (RBP) solution scope is comprehensive and detailed. Generally, a possible ERS solution sits on a spectrum of options which trade-off cost and timeliness to implement, and (broadly speaking) efficiency and competition. The RBP solution favours efficiency and competition but would come at significant cost and time to implement.

In principle, for an ERS to be implementable by Winter 2026 (i.e. in 9 months' time), it must be simple, and utilise functionality in tools, processes and resources that are already in place.[1] It may be necessary to engage a more limited participant pool initially, before expanding to a more diverse set of providers. The ERS must have minimal impacts on responsibilities for our System Operator control rooms close to and in real-time. The

[1] Existing tools and processes we consider might usefully form part of an MVP ERS include dispatchable demand, FlexPoint | Transpower (to provide situational visibility in System Operator control rooms) and/or difference bids functionality (to provide visibility for participants in forward schedules).

situations in which an ERS would be used are already some of the most complex and challenging situations our control room staff coordinate for the industry, with heightened risk and potential consequences for consumers if anything goes wrong (whether in relation to assets or more human factors). This challenge necessitates careful consideration and scenario planning ahead of time so that each unique situation can be securely and confidently navigated in real-time.

We consider that, if these principles are followed in making "minimum viable product" (MVP) design choices, then it should be possible to have an MVP in place for Winter 2026. But it will require the Authority to have decided on the design and requirements, and committed funding, with at least 6 months' lead time for the System Operator to implement it. Irrespective of the operational complexity of the MVP, there remains considerable detail to discover in the procurement and settlement processes, which must begin promptly. Beyond Winter 2026 there may be opportunities to refine or enhance the MVP to better support operability for both providers and System Operator control rooms.

The comprehensive ERS design proposed in the Authority's consultation, which ensures efficiency through sophisticated probabilistic forecasting, would require substantial changes to the System Operator's processes and software systems. Consequently, we think its implementation could have a development lead-time of two years or more. We recommend the Authority prioritises its immediate attention to an MVP that is achievable for Winter 2026, and considers whether other options for market enhancements that improve demand-side participation could be more efficient and effective longer-term. In our view the key factor in incentivising increased demand-side participation is sufficient forward visibility of need, such that providers can make appropriate operational arrangements to reduce demand over system peaks in a way that does not cause undue cost or burden. The current real-time dispatchable demand arrangements do not support this, but we note a parallel between demand-side commitment decisions and those of slow-start thermal generation.

We look forward to engaging the Authority further to consider the design elements of an Emergency Reserve Scheme.

Yours sincerely,

Rebecca Osborne
Head of Market Services

Appendix - Response to Questions

Submitter	**Transpower NZ Ltd. (System Operator)**

Questions		**Comments**
Q1.	Do you agree with our rationale for establishing an ERS? Why/why not?	Yes. We consider there may be significant demand response capacity available and willing to participate in an ERS that mitigates capacity risks, provided the commercial incentives are sufficient, and the design considers demand side factors such as commitment decision timing requirements. Generally, potential demand side providers are not exposed to spot prices and more dynamic forms of retail contracting that include demand response mechanisms beyond time of use tariffs are not yet common. Therefore, it is appropriate to consider an out-of-market signal such as a potential ERS contract to incentivise demand response over peak periods at least for the near term. We support the Authority's consideration of an ERS as a penultimate resort mechanism for securing the system at times of potential shortfall in generation capacity. As was the case on the 9th of August 2021, a confluence of unanticipated events on the system can result in a lack of generation in real-time. An ERS could mitigate potential impacts of such an event on consumers who otherwise may face involuntary load management to stabilise and balance the system, and help to avoid further loss of supply. As the Authority describes, such a scheme would effectively be an insurance policy for consumers to shield them from the worst effects of a generation shortfall — the corollary being the scheme must present a positive balance of benefits to the costs of its implementation and maintenance. To be beneficial the scheme should leverage opportunities to either replace centrally dispatched generation with lower cost alternative energy sources that would not otherwise have been made available during an event, or shift demand away from higher cost peak demand periods. The decision to proceed to implement any ERS should also consider changes since 9th August, particularly investment in grid-scale batteries and retailers contracting for industrial demand response.
Q2.	Are there other factors or risks you consider relevant to our decision to implement an ERS?	The Authority rightly identifies the associated moral hazard with an ERS. There is also significant risk an ERS would diminish demand response incentives within the wholesale market design. It is important to be mindful that in situations that are very fast-moving and not forecastable (such as due to asset failures very close to or in real-time) it is unlikely any ERS could be activated in time to help mitigate the potential for involuntary load-shedding to be required as a last resort.
Q3.	Do you agree with our proposal that only demand-side	Largely. The Authority recognises in its paper that the System Operator expectation is that any ERS results in a reduction in the load supplied from dispatchable generation (or offset from

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	flexibility, including by industrials and aggregations of smaller consumers, should be eligible to provide ERS?	dispatchable demand). Provided distributed generation (DG) is not already providing other system services (i.e. the additionality condition for participation is met) and the DG is not also receiving scarcity-level spot price payments for its generation, it may be efficient to permit DG to be an ERS provider.
Q4.	Are you aware of any off-market generation or batteries that may not be activated in an emergency if they are not included in an ERS? Please provide details of the type and scale of these resources.	Not specifically, but absent a wholesale price response or cognisance of a grid emergency condition or arrangement with the relevant distributor or retailer, there is no reason to believe distributed generation would be automatically operating during a grid emergency. For instance, small-scale standby generation in critical infrastructure facilities has participated ably in demand response schemes in the past but may not typically respond to spot price signals alone.
Q5.	Do you agree with our proposed design elements for procurement of ERS by the System Operator, including the procurement process, timing and trigger?	We strongly recommend further design work to define the operational parameters of the scheme such that economic efficiency is balanced against operability, implementability and minimising operational costs. This is true irrespective of a decision to proceed with either an MVP solution or comprehensive (RBP-like) solution. As the Authority identifies, it is important for minimising implementation cost that the ERS conforms to existing operational processes. This objective could constrain the design of some elements of the scheme, for instance, it may be appropriate to procure ERS contracts using an annual tender process similar to other non-market clearing ancillary services. In relation to the RBP solution, we are not convinced NZGB is an appropriate device for initialising procurement. Using NZGB as a procurement trigger would require significant enhancement to the NZGB calculation ("NZGB-plus"), in the manner RBP describes — developing and integrating probability-of-exceedance (POE) measures for load and intermittent generation forecasts would require a substantial change to our NZGB tool. This type of approach could not be implemented prior to Winter 2026, and we would need to complete considerably more development and investigation work before we could confirm whether it could be implemented before Winter 2027. We note that given ancillary services payments would result directly from the assessment, the inputs to the assessment would likely need to be detailed in the Code.
Q6.	Do you consider that procurement up to 4 weeks in advance of an identified need, coupled with a pre-approved panel of	Further design work would be needed before we could reach any conclusions about the work needed to procure ERS providers, including potential procurement timelines. This is true irrespective of a decision to proceed with either an MVP solution or comprehensive (RBP-like) solution.

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	providers, will be effective and provide adequate time for potential providers and the System Operator?	.
Q7.	Do you agree with our proposed pre-activation and activation processes for use of ERS?	Yes, broadly. The design of the ERS (either an MVP solution or a comprehensive solution) must be operable, in that it must integrate effectively with other activities in the T-36h to T-0 period before a capacity shortfall event. Approaching real time, the existing activities in our processes lead to significant workload and information congestion in our System Operator control rooms. It is therefore vital integration of an ERS into these processes is well-designed, with priority given to minimising coordinator activities ahead of and in real-time. Similarly, the triggers for pre-activation and activation need careful consideration, as does the impact on the wholesale market scheduling and dispatch processes. As with controllable load integration, it is important the coordinators have visibility of the expected outcomes of their actions. Forward scheduling processes should indicate whether instructing controllable load, perhaps followed by activating the ERS, would lead to an adequate level of demand reduction. Or whether further involuntary demand management would be required after activation of these mechanisms.
Q8.	Do you agree that the System Operator should be required to update relevant planning processes to take account of forecast uncertainty? If so, how do you consider this should be done?	While we see merit in this proposal, irrespective of whether an MVP solution or comprehensive solution is selected for development, we do not agree the System Operator "should be required" to change its processes: this is a matter for the System Operator to reflect and act on as it sees fit to meet its obligations under the proposed scheme. Process change always incurs costs and new processes may incur additional ongoing operating costs. New processes may also interact with other System change or processes potentially creating other complexities. We do not take lightly the impact this has on consumers, and we have the responsibility (and extensive contractual obligations) to ensure the costs of business change, and our ongoing operations are reasonable and prudent. System and market operation in general is becoming more complex with increasing electrification and substitution of firm generation capacity with intermittent generation. Modern technology (particularly inverter-based resources) is contributing to this increasing complexity. Forecast uncertainty (in terms of both capacity adequacy and system security) is a significant driver of change in our forward risk assessments. We continually improve our processes to incorporate probabilistic analysis into load and generation forecasts. Currently the NZGB load forecast uses probabilistic-based loads, and currently the NZGB generations scenarios is based off probability of generation

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	being in the market (including intermittent gen). This represents a base and firm generation scenarios. However, to conform to the requirements of a comprehensive, RBP-like ERS solution, further development of NZGB (or indeed creation of a new assessment tool) would be required. This would not be achievable as part of an MVP ERS solution. Consistent with our other processes, we would seek to incorporate forecast uncertainty into ERS procurement and scheduling (pre-activation and activation) to the extent practicable, and to review over time the effectiveness of those processes.
Q9. Do you agree with our proposed compensation and price settings for the ERS, including proposed measures to ensure overall unit costs do not exceed VoLL?	Somewhat. Having a consistent price structure is important for procurement efficiency. There is also efficiency in aligning this cost structure with other non-market clearing ancillary services which are compensated on an Availability Fee + Event Fee basis. Consideration of overall cost of the scheme and limiting that cost to VOLL on a per-MWh basis is likely feasible. Irrespective of the operational complexity of the solution (either the MVP solution or a comprehensive solution), if the Authority decides to proceed to development an ERS, there remains considerable detail to discover in the procurement and settlement processes, which must begin promptly if a Winter 2026 deadline for implementation is to be met.
Q10. Do you consider that the System Operator should also be required to ensure overall costs during an ERS activation are less than VoLL? If so, how do you consider this could be practically achieved in the available time?	No. While this design parameter requires further analysis, we consider it would be operationally impractical to consider the cost of ERS activation dynamically in an event, and that the costs of doing so would seem to outweigh the marginal benefit of constraining the response (compared to, say, assuming an expected number and duration of ERS activations in a given time period). A comprehensive solution may consider a software-based tool for assessing an efficient level of ERS activation for a given event, however the marginal utility of such a calculation is debatable.
Q11. Do you agree with our proposal to 'add back' activated ERS into nodal load schedules to maintain scarcity pricing?	Yes. This proposal is consistent with our Code obligations and operational procedure for managing wholesale pricing during involuntary load shedding. This would be necessary for both an MVP and a comprehensive solution.
• Do you agree with our proposed settings for cost allocation and settlement of ERS costs? Do you consider an alternative cost recovery approach would be preferable and if so why?	Yes. We consider the proposed cost allocation approach to be reasonable for both an MVP and a comprehensive solution.

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Q12. Do you agree with our proposed settings to manage non-performance by ERS providers?	Given the ERS would be a service contracted by the System Operator, we would expect the contractual settings to be defined by the System Operator. For other ancillary services, default contractual obligations (including requirements for testing and monitoring) are outlined in the Ancillary Services Procurement Plan, with specific conditions prevailing in the Ancillary Services Contracts. We anticipate taking a similar approach for implementing an ERS. Different performance criteria and mitigations for non-performance may be implemented depending on the complexity of the scheme selected for design. Irrespective of the operational complexity of the solution (either the MVP solution or a comprehensive solution), if the Authority decides to proceed to development an ERS, there remains considerable detail to develop in relation to contractual and performance obligations. This work must begin promptly if a Winter 2026 deadline for implementation is to be met.
Q13. Do you agree with our proposed information and publication settings to enable the effective operation and monitoring of the ERS? Is there additional information you consider should be made available to potential providers, the Authority, other industry participants or the public?	We agree with the intent behind the reporting and monitoring objectives outlined. The cost of monitoring and reporting should be considered and the reporting regime sized appropriately for the expected benefits.
Q14. Are there other scheme design elements that the Authority should consider?	To repeat, we strongly recommend further design work to define the operational parameters of the scheme such that economic efficiency is balanced against operability and minimising operational costs. We recommend the Authority prioritises its immediate attention to an MVP that is achievable for Winter 2026 and considers whether other options for market enhancements that improve demand-side participation could be more efficient and effective longer-term.
Q15. Do you agree with our high-level evaluation of the proposed ERS against our guiding principles?	We broadly agree, although we note achieving these high-level principles is strongly dependent on the ultimate design of the scheme, which as we have said requires further work to establish operability and cost/benefit trade-offs including relative to an MVP ERS operating in combination with other market enhancements to improve demand-side participation longer-term.
Q16. Is there any additional information the Authority should consider in evaluating	No.

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a proposed ERS design?	
Q17. Do you think there are any elements of the proposed scheme design which require more time for implementation and should be delayed beyond Winter 2026? If so, please identify the relevant elements and indicate when you consider they could be implemented.	Yes. While providing advice to the Authority we have stated that the RBP design for the ERS in its entirety is not implementable before Winter 2026. While an ERS may ultimately be worthwhile and provide benefits to consumers, the RBP design focusses on optimal economic efficiency in its design choices, without due regard to implementation costs. There is considerable further design work required, and we anticipate significant costs in process and system changes to implement an ERS of such a form. In principle, for an ERS to be implementable by Winter 2026 (i.e. in 9 months' time), it must be simple, and utilise functionality in tools, processes and resources that are already in place. It may be necessary to engage a more limited participant pool initially, before expanding to a more diverse set of providers. The ERS must have minimal impacts on responsibilities for our System Operator control rooms close to and in real-time. The situations in which an ERS would be used are already some of the most complex and challenging situations our control room staff coordinate for the industry, with heightened risk and potential consequences for consumers if anything goes wrong (whether in relation to assets or more human factors). This challenge necessitates careful consideration and scenario planning ahead of time so that each unique situation can be securely and confidently navigated in real-time. We consider that, if these principles are followed in making "minimum viable product" (MVP) design choices, then it should be possible to have an MVP in place for Winter 2026. But it will require the Authority to have decided on the design and requirements, and committed funding, with at least 6 months' lead time for the System Operator to implement it. Irrespective of the operational complexity of the MVP, there remains considerable detail to discover in the procurement and settlement processes, which must begin promptly. Beyond Winter 2026 there may be opportunities to refine or enhance the MVP to better support operability for both providers and System Operator control rooms.
Q18. Do you agree with the Authority's proposal to set VoLL at $35,305 per MWh for the purposes of the ERS, and proposal to review VoLL and security standards more broadly?	No comment.
Q19. Are you likely to be interested in participating in an ERS,	N/A.

Questions	Comments
such as the scheme outlined in this paper?	
Q20. Are there any other implementation considerations or related issues the Authority should consider in relation to an ERS?	The comprehensive ERS design proposed in the Authority's consultation, which ensures efficiency through sophisticated probabilistic forecasting, would require substantial changes to the System Operator's processes and software systems. Consequently, we think its implementation could have a development lead-time of two years or more. We recommend the Authority prioritises its immediate attention to an MVP that is achievable for Winter 2026 and considers whether other options for market enhancements that improve demand-side participation could be more efficient and effective longer-term. In our view the key factor in incentivising increased demand-side participation is sufficient forward visibility of need, such that providers can make appropriate operational arrangements to reduce demand over system peaks in a way that doesn't cause undue cost or burden. The current real-time dispatchable demand arrangements do not support this, but we note a parallel between demand-side commitment decisions and those of slow-start thermal generation.
Q21. Are there other matters that the Authority should consider in relation to an ERS?	No.