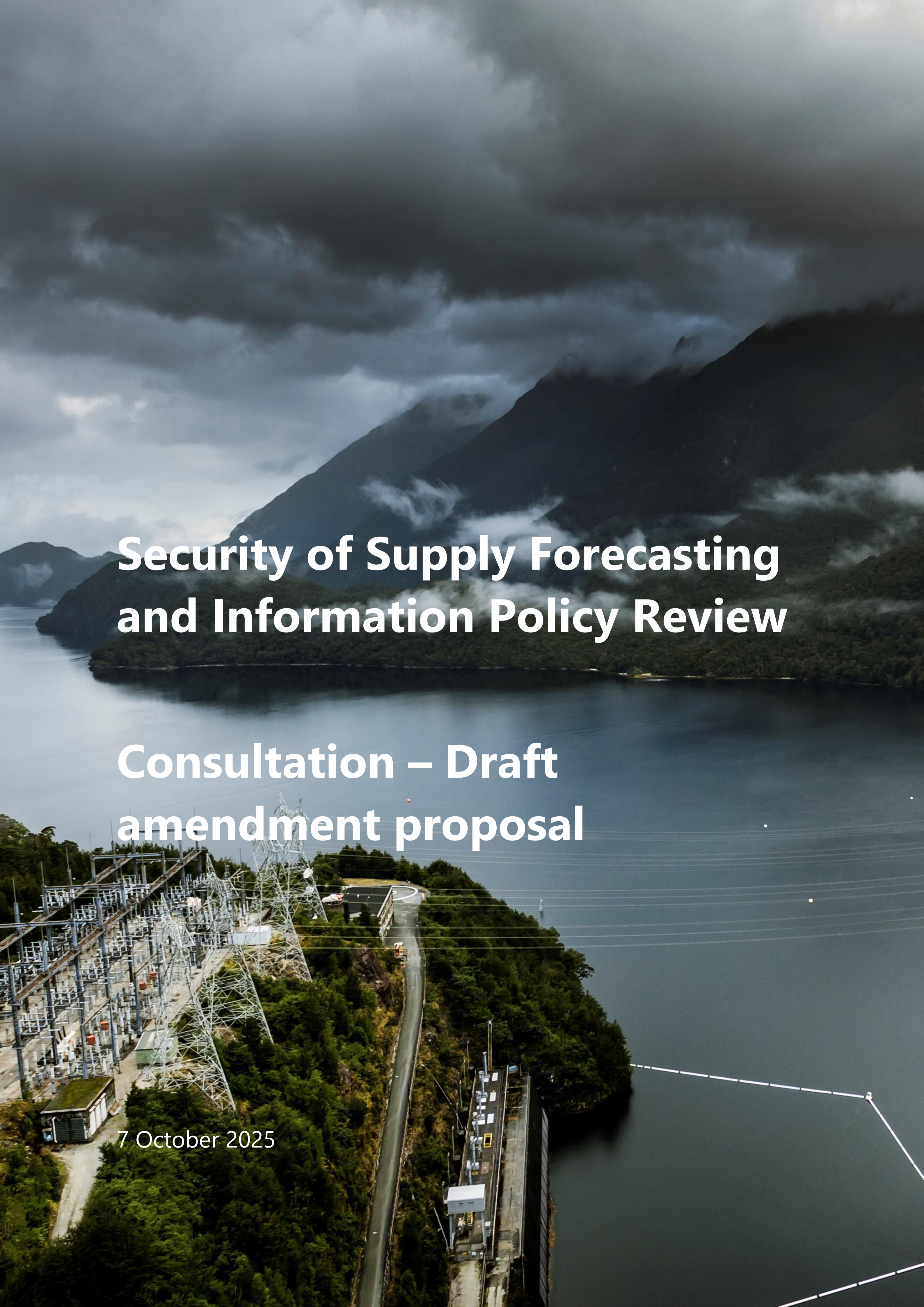

Security of Supply Forecasting and Information Policy Review

Consultation – Draft amendment proposal

7 October 2025

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1 Executive Summary

1. In March 2025 Transpower, in its role as the System Operator, sought feedback on an Issues Paper to inform the scope of a System Operator Security of Supply Forecasting and Information Policy (**SOSFIP**) Review. In April 2025, having considered the feedback we received in submissions and cross-submissions, we published a decision paper. This paper confirmed our decision to proceed with the SOSFIP Review and the topics we had decided to include within the scope of the Review. We also signalled that we would complete our analysis and consultation, and submit a final amendment proposal by the end of 2025 to ensure there is sufficient time for the Electricity Authority (**Authority**) to have the changes in place for Winter 2026.[1]

2. The SOSFIP outlines the approach that the System Operator takes in providing information and forecasting of security of supply. Security of supply in the context of the SOSFIP is the New Zealand power system's current and future ability to meet electricity demand at a national and South Island level.

3. As was confirmed by the feedback we received in response to the Issues Paper, there is general agreement that it is timely to undertake a review to consider whether potential SOSFIP amendments could better support security of supply. Reviews were last undertaken in 2019 and 2022. Since then, the electricity system has accelerated its transition towards increasing dependence on intermittent renewable generation, and risks to the availability of natural gas supplies to substitute for hydro generation during extended dry periods have increased significantly. Long-term arrangements for the necessary back-up to support renewables have not yet emerged, and delivery lead times for coal are long.

4. On 1 October 2025 the Government announced its decisions following the 2025 review of the New Zealand electricity system.[2] These include a decision to "work with Transpower, as the System Operator, to ensure [its] security-of-supply assessments are fit for purpose for our evolving energy system."[3] We will work with the Government and its nominated agencies to respond to this decision. Our view is that the SOSFIP amendment proposals set out in this paper are consistent with the Government's expectation and a no-regrets development that can better support security of supply from Winter 2026.

5. The process the System Operator must follow to complete a Review of the SOSFIP is set by the Authority in the Electricity Industry Participation Code 2010 (**Code**). The scope of information we must provide with any amendment proposal is also specified in the Code. The Authority must decide whether to approve the amendment proposal and, if so, when it will take effect. Ultimately, it is the Authority's decision whether and what changes are made to the SOSFIP.

6. The purpose of this consultation paper is to seek feedback on our draft proposals to amend the SOSFIP. The feedback we receive will inform the final amendment proposal we submit to the Authority later in 2025. Our Review of the SOSFIP has resulted in some proposals that would require SOSFIP amendments to proceed, and some other proposals that we could progress without SOSFIP amendments.

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1 The 2025 SOSFIP Review Issues Paper, the submissions and cross-submissions we received in response to it, and our Summary and Decision document are available on our webpage: [Invitation to Comment: Security of Supply Forecasting and Information Policy (SOSFIP) Review Issues Paper 2025 (Closed) | Transpower]

2 [Securing New Zealand's energy future | Beehive.govt.nz]

3 [Fact Sheet: Strengthening the regulatory framework for dry years],

7. Our paper sets out our consideration and conclusions in relation to each of the topics we have reviewed, provides our draft of the proposed SOSFIP amendments, a statement of the objective of each proposed amendment, our consideration of the costs and benefits, and evaluation of any alternative means of achieving the objectives of the proposed amendment where we have identified any. We do not consider any of the proposed SOSFIP amendments can reasonably be supported by a quantitative cost-benefit assessment. The topics we have considered through this SOSFIP Review, and the proposals we are now seeking feedback on are summarised below.

1.1 Review of key ERC and SST assumptions

8. **Review of thermal fuel assumptions:** We propose to introduce a second Electricity Risk Curves (**ERC**s) and Simulated Storage Trajectories (**SST**s) scenario based on contracted thermal fuel quantities. This scenario would work alongside the current physical capability model to improve transparency on energy risk and market responses, while maintaining the physical capability model for setting risk status and actions. Our proposal is to give effect to this approach through a SOSFIP amendment. Taking this proposal forward is contingent on the Authority making permanent our ability to require participants to provide us with contracted thermal fuels information (confidentially).[4]

9. **Updating the time-to storage projection**: Participants have raised concerns that the current worst-case SST, used for estimating time-to Alert and Official Conservation Campaign (**OCC**), is overly pessimistic for longer horizons. We propose to adopt a new "time-to SST" approach, progressively less conservative further into the future, to provide more realistic time-to estimates. The new approach to calculating and using the time-to SST would be published through an update to our Energy Security Outlook 101 (section 9.4). Progressing this proposal does not require a SOSFIP amendment.

10. **Adjusting Watch curve trigger:** To ensure Watch status always precedes Alert status, we propose to update the Watch curve by applying a 200 GWh adder above the Alert curve with this default Watch adder increased (not decreased) if necessary to match the simulated future storage projections (used to determine the ERCs) with the biggest drop across its first month. This approach uses analysis we already do to determine the ERCs and giving effect to our draft proposal requires a SOSFIP amendment.

11. **Minimum duration for Alert status:** To reduce uncertainty and avoid the potential to "flip-flop" in and out of Alert status, we propose to introduce a minimum Alert period of four weeks unless storage recovers above the Watch curve or moves to Emergency status. A SOSFIP amendment is proposed to give effect to this approach.

1.2 Linkage between energy and capacity risks

12. **Improving capacity risk assessment in the ERCs and SSTs:** We propose to capture more capacity-related issues within the ERCs and SSTs by shifting from a day-night model to a 3-hour model. Implementing these changes does not require a SOSFIP amendment.

13. **Using supplementary information to inform capacity risk indicators:** We also propose to enhance our New Zealand Generation Balance (**NZGB**) assessment of capacity risks by providing

4 Earlier in 2025 the Authority approved an urgent Code amendment that has enabled us to source this information confidentially from participants, and it has recently consulted on a proposal to make that amendment permanent.

additional scenarios to reflect constraints on hydro schemes as they approach their lower operating range of storage, extending the assessment horizon from 200 days to 12-months and incorporating an NZGB capacity risk assessment into our monthly Energy Security Outlooks. Implementing these changes does not require a SOSFIP amendment.

1.3 Consideration of geopolitical and asset risks

14. **Expand the scope of scenarios:** Stakeholder feedback to the Issues Paper identified a need to consider the extent to which the SOSFIP should consider the implications of the increasing influence of global geopolitical factors on energy markets and supply chains, particularly in relation to thermal fuel supply disruptions. Our proposal is to expand Part 13 of the SOSFIP to require us to consider scenarios related to both thermal fuels, and to loss of major generation and/or transmission assets for several months.

1.4 Contingent storage buffer access arrangements

15. **Contingent storage release boundary (CSRB) default buffer value:** Following analysis of operational constraints at key hydro catchments (Waiau and Tekapo), a higher, seasonally profiled default buffer for the Alert Contingent Storage Release Boundary (CSRB) is proposed to better reflect operational limitations and improve certainty. We propose an amendment to the SOSFIP to permanently adjust the default buffer, including to promote certainty about the circumstances in which contingent storage can be accessed.
16. **CSRB buffer discretion:** We propose to retain the existing discretion in the SOSFIP that provides for us to determine and publish a buffer different to the default because this ensures we are able to respond quickly to the unique operational circumstances giving rise to the potential need to access contingent storage at the time. We propose to add a requirement into the SOSFIP that we publish the process we use to decide on a temporarily different CSRB buffer.

2 Introduction

17. In our role as System Operator, and in agreement with the Electricity Authority (**Authority**), we are consulting to seek your feedback on our draft proposals to amend the Security of Supply Forecasting and Information Policy (**SOSFIP**).

18. The SOSFIP is one of the system operations documents that is incorporated by reference in the Electricity Industry Participation Code (**the Code**) under clause 7.4.[5] It describes how the System Operator prepares and publishes information to assist participants to manage security of supply risks.

2.1 Why are we consulting?

19. It is timely to undertake a review to consider whether potential SOSFIP amendments could better support security of supply. Reviews were last undertaken in 2019 and 2022. Since then, the electricity system has accelerated its transition towards increasing dependence on intermittent renewable generation, and risks to the availability of natural gas supplies to substitute for hydro generation during extended dry periods have increased significantly. Long-term arrangements for the necessary back-up to support renewables have not yet emerged, and delivery lead times for coal are long. We have also received submissions from stakeholders indicating support for a review of the SOSFIP.

20. In March 2025 Transpower, in its role as the System Operator, sought feedback on an Issues Paper to inform the scope of the 2025 SOSFIP Review.[6] We also sought input on the urgency with which any proposed changes should be made. In April 2025 we published a Summary and Decision document presenting our decisions following review of submissions and cross-submissions and communicating next steps in relation to the review. It also summarised the range of feedback we received in response to the Issues Paper, some of which was for other parties to consider. Where necessary we informed relevant government and regulatory stakeholders of such feedback.

21. The Issues Paper consultation confirmed clear support for undertaking a review of the SOSFIP. Our Summary and Decision document confirmed our plan to our decision to proceed with the SOSFIP Review and the topics we had decided to include within the scope of the Review. We also signalled that we would complete our analysis and consultation, and submit a final amendment proposal by the end of 2025 to ensure there is sufficient time for the Authority to have the changes in place for Winter 2026.[7]

22. On 1 October 2025 the Government announced its decisions following the 2025 review of the New Zealand electricity system.[8] These include a decision to "work with Transpower, as the System Operator, to ensure [its] security-of-supply assessments are fit for purpose for our

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5 The current SOSFIP can be found at: https://www.transpower.co.nz/system-operator/securitysupply/security-supply-forecasting-and-information-policy.

6 Invitation to Comment: Security of Supply Forecasting and Information Policy (SOSFIP) Review Issues Paper 2025 (Closed) | Transpower

7 The 2025 SOSFIP Review Issues Paper, the submissions and cross-submissions we received in response to it, and our Summary and Decision document are available on our webpage: Invitation to Comment: Security of Supply Forecasting and Information Policy (SOSFIP) Review Issues Paper 2025 (Closed) | Transpower

8 Securing New Zealand's energy future | Beehive.govt.nz

evolving energy system."[9] We will work with the Government and its nominated agencies to respond to this decision. Our view is that the SOSFIP amendment proposals set out in this paper are consistent with the Government's expectation and a no-regrets development that can better support security of supply from Winter 2026.

2.2 Previous SOSFIP Reviews

23. We undertook previous reviews of the SOSFIP in 2019 and 2022.[10]

24. The Authority commissioned MartinJenkins to undertake an operational review of the 2021 dry year. This review included the dry year risk regime which includes the SOSFIP and Emergency Management Policy (**EMP**). While the review found that the security of supply framework worked as intended and the dry year situation was managed, it highlighted areas of improvement for the SOSFIP and EMP. These included consolidating the different Electricity Risk Curves (**ERCs**) as these caused confusion, removing subjective elements of the policy where possible (for example about how much gas will be reallocated to generators from large industrial users during a dry year) and making the trigger for commencing increased reporting more deterministic.[11]

25. After receiving the findings of the MartinJenkins report the Authority and Transpower initiated a SOSFIP Review that resulted in SOSFIP amendments including improving understanding of assumptions around gas reallocation used in the ERCs, simplifying reporting by retaining only the percentage risk curves with the status curves aligned, clarifying that a medium demand forecast be used in determining the ERCs, clarifying when the triggers for the System Operator to produce daily security of supply reporting are met, and encouraging proactive information disclosure to the System Operator.

26. Transpower consulted on changes to the SOSFIP and EMP from 29 March to 16 April 2022 and submitted recommendations to the Authority in May 2022.[12]

27. The Authority then consulted on the proposal to replace the SOSFIP in November 2022,[13] and decided to replace the SOSFIP in April 2023.[14] The current SOSFIP came into effect in June 2023.[15]

2.3 Requirements for amendment of the SOSFIP

28. We must submit any proposed amendments to the SOSFIP to the Authority for approval (clause 7.13 of the Code). The requirements for proposals to amend or replace system operation documents (including the SOSFIP) are contained in clauses 7.13-7.22 of the Code.

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9 Fact Sheet: Strengthening the regulatory framework for dry years,
10 https://www.transpower.co.nz/system-operator/information-industry/sos-policies/sosfip-consultations
11 The Authority published the MartinJenkins October 2021 review report as Appendix A to its 2021 Dry Year event review consultation paper (December 2021).
12 SOSFIP/EMP Review 2022 – Consultation Paper
13 https://www.ea.govt.nz/projects/all/system-operation-documents/consultation/amendments-to-the-security-of-supply-forecasting-and-information-policy-2022/
14 https://www.ea.govt.nz/documents/2712/2022_SOSFIP_Summary_of_Submissions.pdf
15 https://www.ea.govt.nz/documents/2711/SOSFIP.pdf

29. The Authority must consent to the consultation before the System Operator consults on a proposal to amend a system operation document (clause 7.16).

30. We are required to consult "with affected participants or persons that represent the interests of those persons likely to be affected by the proposed amendment" before submitting the proposed amendments to the Authority for approval (clause 7.20 of the Code).

2.4 2025 SOSFIP Review scope

31. The Issues consultation Summary and Decision paper confirmed the scope of the 2025 SOSFIP Review, which is to consider potential amendments to section 6 (Determining the electricity risk curves), section 12 (Simulated storage trajectories), and section 13 (Thermal fuel supply disruptions). This includes the following specific topics:

- Physical versus contracted capability in the ERCs
- Assessing criteria used in the application of the contingent storage release boundary (**CSRB**) buffer discretion
- Determination and use of the worst-case Simulated Storage Trajectory (**SST**)
- Watch curve parameters to ensure Watch status will always be triggered before Alert.
- Review of the assumptions used in the ERCs and SSTs, including the assumptions about thermal fuel availability and generator operational limitations.

32. We also confirmed the 2025 SOSFIP Review scope includes:

- Providing greater clarity about how we assess both energy and capacity risks that may trigger access to contingent hydro storage
- Our criteria and process for exercising any operational discretion the SOSFIP provides for (including in relation to the CSRB buffer discretion should it be retained in some form)
- The extent to which the SOSFIP should consider the implications of the increasing influence of global geopolitical factors on energy markets and supply chains (domestic and international), particularly in relation to potential thermal fuel supply disruptions.
- Meridian's proposal to permanently lift the CSRB buffers, in order to provide time necessary to complete robust analysis including of the costs and benefits of the proposal, allow for further consultation with stakeholders, and support the Authority's consideration of any final SOSFIP amendment proposal.

33. This paper sets out our consideration of these topics in the following sections of this paper:

- Reviewing key assumptions used in determining the ERCs and/or SSTs (Section 4)
- Providing greater clarity about how we assess both energy and capacity risks (Section 5)
- Assessing wider risks in the SOSFIP (Section 6)
- Review of the CSRB buffers in the SOSFIP and providing greater clarity of the System Operator application of discretion (Section 7)

34. Addressing some of these issues requires change to the SOSFIP and some do not. Where changes to the SOSFIP are required, these are proposed. In some instances, changes to other System Operator documents and processes are required or there are changes that other stakeholders would need to address.

35. We welcome any feedback on the SOSFIP and our proposed amendments to it, including responses to our specific questions and any other potential amendments we should consider.

Question 1

Do you support our proposal to amend the SOSFIP?

Question 2

Are there any other SOSFIP amendment options we should consider? Please explain your preferred option in terms consistent with the Authority's statutory objective in the Electricity Industry Act 2010 and consideration of practicality of the solution to implement it.

2.5 How you can have your say

36. We have included a Word document, for the convenience of submitters, which incorporates all the questions contained in the consultation paper. You can use this for your submission if you would like to.

2.6 Consultation period

37. The consultation period is four weeks commencing Tuesday, 7 October. Submissions are due by 5pm on Tuesday, 4 November 2025. This is followed by a one-week period for cross-submissions. Cross-submissions are due by 5pm on Tuesday, 11 November 2025.

38. Please send submissions and cross-submissions to system.operator@transpower.co.nz. We will acknowledge receipt of all submissions and cross-submissions. Submissions and cross-submissions will be published on our website at System Operator Consultations | Transpower

39. If your submission or cross-submission contains confidential material, please ensure this is clearly identified and provide a version of your submission or cross-submission that can be published.

40. Please note that all information provided to Transpower is subject to potential disclosure under the Official Information Act 1982. Clause 7.20(4) of the Code also requires that the System Operator provide a copy of each submission received to the Authority.

41. If you have any questions about this consultation, please send them to system.operator@transpower.co.nz. Your questions and our responses to them will be published on our website for reference by other submitters and stakeholders.

2.7 Next steps

42. We will carefully review all the submissions and cross-submissions we receive, including preparation of a summary and response document, and (if applicable) revising our proposed amendments to the SOSFIP.

43. Subject to the nature and content of submissions we receive, we are aiming to submit proposed amendments to the Authority by the end of 2025. Clause 7.21(1) of the Code sets out the requirements for the information the System Operator must provide to the Authority.

44. Once we have provided it to the Authority we will publish our final SOSFIP amendment proposal.

3 Context for the SOSFIP

45. The SOSFIP is a system operation document approved by the Authority and incorporated by reference into the Code. [16] The SOSFIP describes how the System Operator prepares and publishes information to assist participants to manage security of supply risks.

46. It is the role of Transpower as System Operator to implement and comply with the SOSFIP, and the role of the Authority to approve it. The System Operator must comply with the SOSFIP that is current at the time.[17]

47. The Authority is responsible for the overarching market design the SOSFIP sits under and must approve any changes to the SOSFIP consistent with its statutory objective.[18] The interrelationships between key security of supply documents are illustrated in Figure 1.

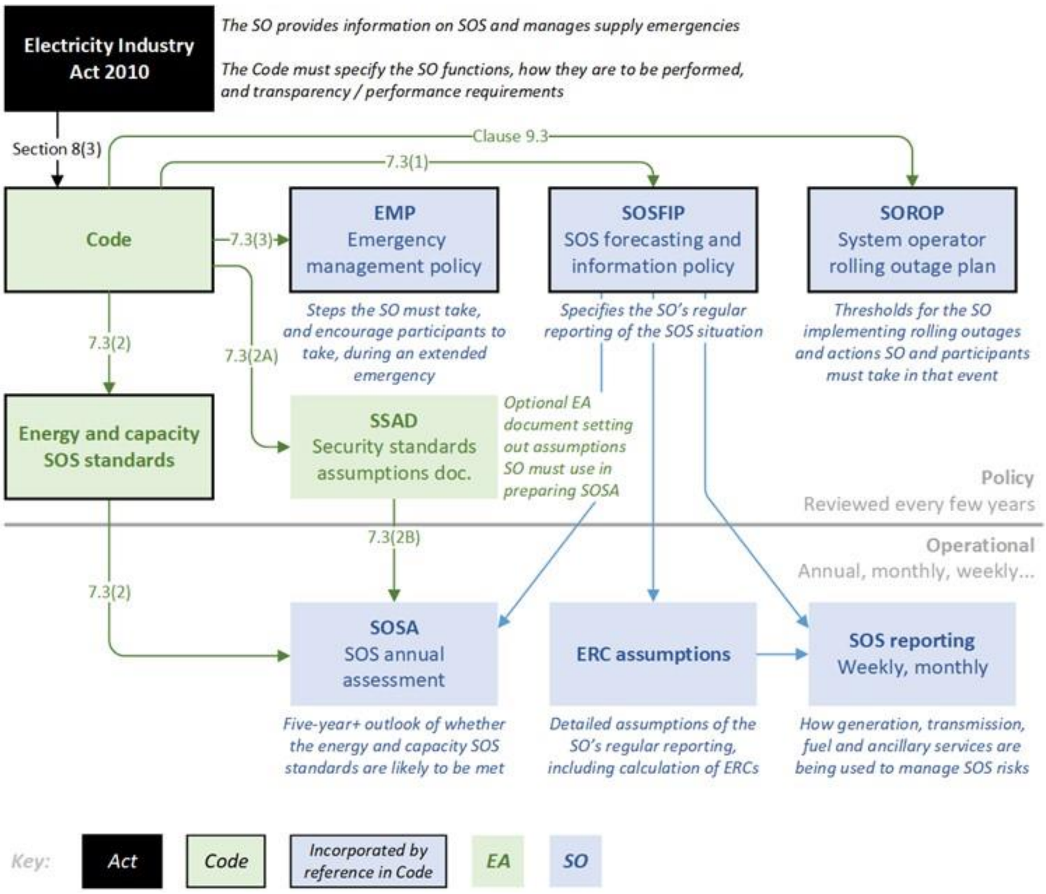

Figure 1 Security of supply key document inter-relationships

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16 The current SOSFIP can be found at: https://www.transpower.co.nz/system-operator/securitysupply/security-supply-forecasting-and-information-policy.

17 The Electricity Industry Act 2010 (section 8(2)(a)) requires the System Operator to provide information, and short-to medium-term forecasting on all aspects of security of supply. The Code (clause 7.3(1)) requires that the System Operator explain how it will do this through the SOSFIP and stipulates the System Operator is responsible for implementing and complying with the SOSFIP. The System Operator may also propose changes to the SOSFIP (clause 7.13(1)) which may ultimately be approved by the Authority (clauses 7.21(2)).

18 The Electricity Industry Act (s15) sets the Authority's statutory objective: The main objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

48. The combination of these policies and plans sets out the protocols and contingency plans used to protect New Zealand from running out of electricity supply in the weeks and months ahead (supply shortage).[19]

49. The SOSFIP sets out how security of supply information and the risk of supply shortage must be forecast by the System Operator, in the first instance to provide information to inform an industry response to mitigate this risk. It also sets out the basis on which other actions are triggered if the industry response has not sufficiently mitigated the risk.[20]

50. The first step (at **Watch** status) requires the System Operator to increase the frequency and type of security of supply information and forecasting it provides to signal the heightened energy risk to industry.

51. If the industry response does not arrest falling hydro storage levels, access to extra water storage in Lakes Pūkaki, Tekapo and Hāwea is triggered at **Alert** status. Resource consents for these catchments permit generators to access more water only when it is needed to mitigate an electricity supply emergency (**contingent storage**).

52. If hydro storage levels continue to fall, then the System Operator may be required to initiate an Official Conservation Campaign (**OCC**) asking New Zealand households and businesses to voluntarily reduce electricity consumption (**Emergency** status). Additional contingent storage at Lake Pūkaki is available under an OCC.

53. If these actions still do not resolve the risks the last resort action is for the System Operator to instruct rolling outages that will turn off electricity supply to different locations around the country on a rolling basis. This is covered in the System Operator Rolling Outage Plan (**SOROP**).[21]

3.1 The security of supply risk framework prioritises a market-led approach

54. The security of supply risk management framework prioritises a market-based industry response designed to ensure other fuel sources are being utilised to the extent practicable before contingent storage is accessed. This is intended to provide time for inflows to arrive in the form of rain and snow melt and also holds back some hydro storage against the risk of unplanned outages affecting other generation assets during an extended dry period. Box 1 provides the overview of the framework that has informed both the System Operator 2019 and 2022 SOSFIP Reviews.

55. New Zealand's electricity system is hydro-dominated, and unlike most other electricity systems world-wide it has no ability to mitigate supply risks through an interconnection to other electricity systems. Consequently, the key risk that our security of supply policies are currently

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19 Part 7 of the Code sets out the System Operator's obligation to prepare and publish the SOSFIP and the Emergency Management Plan (**EMP**). Part 9 of the Code sets out the circumstances when the System Operator must commence an official conservation campaign (**OCC**). Part 9 also sets out the System Operator's obligation to prepare and publish the System Operator rolling outage plan (**SOROP**) and the System Operator may request specified participants to develop a participant rolling outage plan (**PROP**). Together, these policies and obligations relate to managing an extended emergency in which the ability of the power system to meet demand over an extended period is at risk.

20 While the basis for the trigger is set in the SOSFIP some of the actions are covered in the Emergency Management Policy, Part 9 of the Code and SOROP.

21 System Operator Rolling Outage Plan – effective September 2024

designed to protect against is the risk of low inflows (unseasonally low rain and/or snow melt) leading to an inability to supply electricity over time. This is known in the industry as the 'dry year energy risk'.

56. As the transition to more renewable sources of energy has progressed, demand for electricity has increased, and peak (instantaneous) demand has grown. Compounding this, thermal generator assets have been retired, gas production has become increasingly constrained and gas availability contested, more energy is supplied by intermittent renewables (currently mostly wind), delivery lead times for coal are long, and long-term arrangements for the necessary back-up to support renewables have not yet emerged.[22] As a consequence, New Zealand's exposure to energy risks has increased and the risk of being unable to supply peak demand has emerged as a secondary but also a key security of supply risk.[23] This risk to supplying peak demand is known as 'capacity risk' and in New Zealand it typically occurs on cold, still winter mornings or evenings with lower quantities of committed generation in the market.[24]

57. While the SOSFIP contemplates energy shortages, it does not directly set out how the System Operator must monitor or inform the market to mitigate capacity risks. The System Operator uses other tools to monitor and mitigate capacity risk, such as the annual Security of Supply Assessment (**SOSA**), New Zealand Generation Balance (**NZGB**), monitoring 'residual' generation offers,[25] monitoring storage levels and inflows for each of the key controlled storage hydro lakes including all those with contingent storage, power system analysis for regional security of supply issues, and ongoing engagement with generators to ensure its intelligence about operational capabilities and constraints remains current. In the week-ahead of real-time we apply our Low Residual Situations process to coordinate an industry response to Low Residual Situations (tight capacity situations). We have separately indicated our intention to review and propose amendments to the Policy Statement to formalise the Low Residual Situations process, and we will also consider whether NZGB arrangements should be formalised through the Policy Statement. [26]

Box 1: The Security of Supply (Energy Shortage) Framework[27]

New Zealand is characterised by a high proportion of hydro electricity generation, relatively low hydro storage quantities, and historically large fluctuations in rainfall patterns between months, seasons, and years. This makes New Zealand susceptible to dry events which can constrain hydro-electricity generation.

The Authority has developed a framework to encourage the electricity market to conserve hydro storage when dry year conditions emerge to ensure there is sufficient energy available through the winter months. This is done principally through electricity spot price signals

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22 The Commerce Commission is currently consulting on its draft determination to authorise an agreement between the Gentailers that would support the retention of all three Rankine units at Huntly until 2035: Agreements signed, Huntly capacity to support national energy security | Genesis NZ

23 See our most recent annual security of supply assessment: SOSA 2025.

24 As an example a one degree drop in temperature across the country can result in an ~140 MW increase in electricity consumption.

25 Invitation to Comment: Low Residual Review Consultation (Closed) | Transpower

26 Low Residual Review Consultation Responses We expect to consult on the 2025/26 Policy Statement review proposals later in 2025. Information about our current Low Residual Situations process is available on our webpage: Process for notifying and managing energy or reserve shortfalls | Transpower

27 See also SOSFIP consultation December 2018 web and SOSFIP and EMP consultation 2022.pdf, Box 1 has been updated for clarity and to reflect the Real-time Pricing scarcity pricing regime that took effect in November 2022

encouraging balanced use of different hydro catchments, greater use of thermal generation and some reduction in electricity demand.

The security of supply (energy shortage) framework is comprised of:

- an energy-only electricity market based on spot prices, with hydro generators valuing their hydro storage based on the current storage levels, expected generation and expectation of future hydro inflows.

  As an example, if a hydro generator wants to conserve its hydro storage (i.e. an increase in the value of its available stored hydro) they would increase the price at which their hydro generation is offered into the spot electricity market. This would result in less generation from the hydro generator(s) with high water values (thus conserving their storage) and more generation from other resources (such as thermal generation, other hydro generators with lower water values) as well as demand response.
- provision of scarcity prices[28] in the wholesale market when there is insufficient supply to meet the demand requirements. This is intended to create operational and investment incentives to increase supply and reduce demand when these situations occur.
- an OCC when the risk of shortage reaches and expected to remain below the emergency curve (which is underpinned by the 10% risk curve) for at least a week.
- a Customer Compensation Scheme (CCS) which requires retailers to reimburse qualifying customers a weekly payment (currently $12) during an OCC, to incentivise the market to avoid reaching this trigger level.
- implementation of planned rolling outages when the risk of shortage reaches a certain trigger level (extended period of unplanned shortages in the next 35 days if an OCC has commenced or likely to commence).
- the provision of forecasts and information to support the above.

The Electricity Industry Act 2010 requires the System Operator to provide information, and short-to medium-term forecasting on all aspects of security of supply. The Code requires that the System Operator explain how it will do this through a Security of Supply Forecasting and Information Policy (SOSFIP). The System Operator is responsible for operating the policy and preparing changes to the policy, often in conjunction with the Authority. The Authority is responsible for the over-arching market design which the policy sits under and must approve any changes to the policy.

3.2 The SOSFIP defines the Electricity Risk Curves (ERCs)

58. A key role of the SOSFIP is to define how risks to the system are quantified and the primary tools utilised by the System Operator are the interaction of Electricity Risk Curves (**ERCs**) and Simulated Storage Trajectories (**SSTs**). Together these show how actual hydro storage and

28 The current energy scarcity prices are $21,000/MWh, $31,000/MWh and $50,000/MWh for the first 5%, 15% and the remaining 80% of demand reduction. These were last updated in March 2025. Code Amendment (Scarcity Pricing) 2025 | Electricity Authority

projected hydro storage (simulated as SSTs) are tracking relative to a calculated risk of energy shortage (modelled as ERCs). The risk of energy shortage is considered to be the risk of running out of controlled hydro storage in the next 12 months, inclusive of contingent storage.[29]

59. A key principle in determining the ERCs is that short-term market behaviour would seek to conserve hydro storage, which implies minimising hydro generation and increasing other (predominantly thermal) electricity generation, and/or reducing electricity demand. Therefore, in determining the ERCs, it is assumed that market price signals would incentivise market behaviour that results in:

- Electricity demand reduction (demand response) in response to elevated market prices associated with low hydro storage; and/or
- Increased thermal generation and the required fuel (coal, diesel and gas) required to do so.

60. The System Operator applies the rules set in the SOSFIP to forecast the risk of an energy shortfall in the power system: that is the risk of running out of controlled hydro storage, which would result in an inability to supply households and businesses across the country with electricity. The forecast of the dry year energy risk is recalculated at least monthly, and published in the System Operator's Energy Security Outlook.

61. An extended dry period without a commensurate reduction in hydro generation will result in rapidly falling hydro storage levels. This can also give rise to potential capacity risks as the flexibility in operating hydro schemes becomes limited under low storage and low inflow conditions, reducing their ability to ramp up to meet peak load periods. We have other tools for assessing capacity risks as discussed in paragraph 5757.

3.3 The ERCs assume the power system's primary objective is to conserve water

62. To calculate the ERCs, the System Operator must estimate what resources are available to conserve hydro generation. Therefore, the ERCs are dependent on uncertain and subjective variables, such as future hydrological inflows, outages, assumed demand side response, and availability of thermal fuels.

63. Each time the System Operator calculates the ERCs it assesses and adjusts the assumptions based on the information available to it at the time. The accuracy of the ERCs is therefore inherently dependent on participants' disclosure of accurate information about generation assets and fuel supply arrangements to the System Operator in a timely way. Much of this information is disclosed confidentially.

64. A key assumption is that market participants' contracting and trading decisions will secure thermal fuel supplies at the *maximum* capability to do so: coal supplies will be replenished at the maximum import capability and any gas production not typically used by other users (including industrial gas users) during extended dry periods will be used for electricity generation. This assumption is based on the New Zealand energy-only market design in which price signals will incentivise market participants to access all the required thermal fuels available to them, thus minimising hydro generation in times of (or in anticipation of) extended dry

29 Also known as available storage, the hydro storage lakes modelled in the ERCs are lakes Pūkaki, Tekapo, Manapouri, Te Anau, Hāwea and Taupo. Storage in lakes Pūkaki, Tekapo, and Hāwea, include some storage (contingent storage) which under resource consents is only accessible in an electricity supply emergency situation.

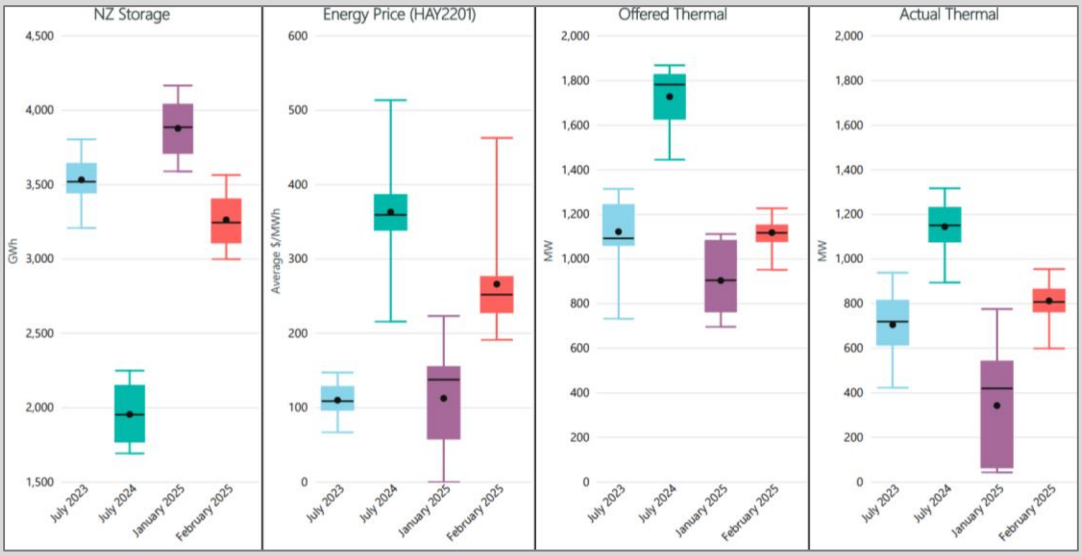
periods. The 2024 Government Policy Statement (**GPS**) broadly reconfirmed the Government's ongoing support for this approach.[30]

Box 2: Higher spot prices for energy are a function of participant offers, demand and the availability of fuel and generation at the time

The energy-only market design is based on offers determined by market participants. They make decisions about offering generation and demand resources into the market at the prices and quantities that are determined by them.[31] The wholesale electricity market is cleared based on these resources with the wholesale electricity price set by the offer price for the marginal resource(s) needed to meet the demand and reserve requirements.

Under this market framework, when there is declining hydro storage and anticipation of extended dry periods the available water becomes more valuable. This is reflected via higher offer prices for hydro generation in the market (signalling the increased value of water). As a result, other resources (primarily thermal generation but also demand response) would increasingly be used ahead of hydro generation. The net effect being reduced hydro generation, allowing available hydro storage to be conserved for higher valued use until it rains. An example of higher valued use could be to prevent load curtailment if the thermals tripped out.

Historically, we have seen thermal generation increase and prices rise when hydro storage reduced as shown below (July 2023 vs July 2024). Looking at February 2025, there was some increase in thermal generation offers as hydro storage dropped. However, two large thermal generators were on outage and other offered thermal generation was not fully dispatched because its offer prices were higher than hydro offer prices.



30 2024 GPS including (for example) paragraph 8: The Government's role is to ensure clear and consistent regulatory settings, reflected in market rules with robust compliance monitoring and enforcement, that enable an efficient market anchored by accurate price signals, and effective risk management tools and competition

31 The exception is bids submitted by electricity distribution companies in response to a low residual situation. The price is specified in the Code.

These increased prices can sometimes be large and persist for extended durations. The Authority has a stress test regime to ensure participants are aware of and acknowledge their risk management positions. Disclosing participants need to report the results to their Board and the NZX. This regime is intended to encourage participants to actively consider and manage their exposure to spot price risks (e.g. through forward contracting).

Ensuring sufficient resources are available to ramp-up to reduce hydro generation if there is an extended dry period is the responsibility of market participants through investment in alternative fuel supply, new generation and demand-side resources and contracting. The 2024 GPS reiterated this:[32]

> "16. Reliability requires enough investment in power stations, storage devices and demand-side response capability to meet today's needs, as well as tomorrow's expected needs. This includes a reasonable buffer to insure against variability in hydro, wind and solar generation and failures in plant or networks.
>
> 17. Clarity of incentives and accurate prices signals in the wholesale electricity market are critical to achieving efficient reliability and security of supply.
>
> 18. Individual wholesale market participants are responsible for managing their own supply risks in response to efficient price signals.
>
> 19. This recognises that individual wholesale parties are best placed to understand the risks they face and how best to 'insure' against those risks for their particular circumstances.
>
> 20. It is therefore important:
>
> a) For each wholesale buyer and seller of electricity to have in place risk management arrangements (such as contract cover and demand-side response, among other measures) appropriate to its wholesale market risk position; and
>
> b) For wholesale buyers and sellers to regularly sign off on their company's risk management position.
>
> 21. Neither the Government nor the Authority nor the System Operator will step in to insulate wholesale market participants from risk or to protect them from their failure to manage their own energy supply risks. To do so would only increase the risk of shortage. Such interventions can cause a vicious circle because they can undermine incentives on market participants to manage their own risks properly, chilling hedging and new investment leading to increased scarcity, more periods of high prices and reduced security."

65. Figure 2 provides an example of the ERCs and actual hydro storage. As the information used to underpin the assumptions changes, the risk curves often also change when they are recalculated. Recalculations are not 'reverse calculated' for periods that have already passed. This causes the vertical step changes in the risk curves illustrated and ensures that the curves for previous periods show the risk as it was calculated at that point in time. This ensures that

32 See [Government Policy Statement on Electricity - October 2024.pdf]

when market analysis is done on previous periods, the actual risk the market responded to at the relevant time is shown.

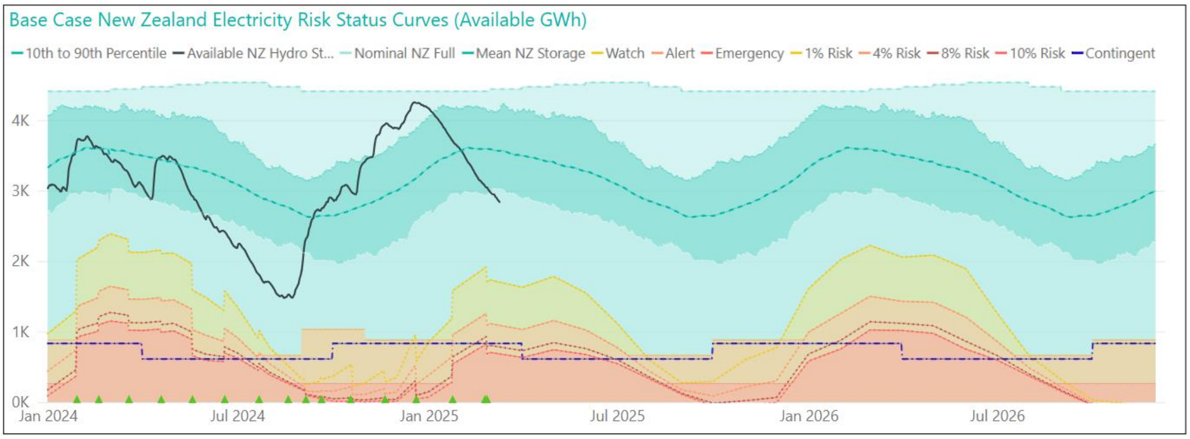


Figure 2 Example of ERCs

66. The ERCs (yellow, orange, red) estimate the risk of hydro storage running out over the next 12 months assuming market participants respond as if their primary objective is to minimise the use of hydro generation. The purple line indicates the amount of controlled hydro storage that is contingent storage. If actual hydro storage (the black line) crosses these curves it triggers actions for the System Operator and/or market participants:

- **Watch** curve (yellow) - a 1% risk of future shortage: the System Operator increases the frequency and scope of security of supply information updates to daily (including hydro storage level, estimated time to Alert status and OCC initiation) and produces Energy Security Outlooks including recalculated ERCs fortnightly instead of monthly. The Electricity Risk Meter status is set to Watch.
- **Alert** curve (orange) – the higher of a 4% risk of future shortage and the sum of all contingent hydro storage and a 50 GWh buffer[33]: access to Alert contingent storage in Pūkaki, Hāwea and Tekapo is triggered. The Electricity Risk Meter status is set to Alert.
- **Emergency** curve (red) – the higher of a 10% risk of future shortage and the sum of emergency contingent hydro storage and a 50 GWh buffer[34]: if actual hydro storage is forecast to stay below the Emergency curve for a week or more, or as otherwise agreed with the Authority, an **OCC** is called and the Electricity Risk Meter Status is set to Emergency. When an OCC is called, additional contingent storage in Pūkaki can be accessed. If an OCC is triggered or likely to be triggered and the System Operator forecasts sustained unplanned shortfalls over the next 35 days, then it can make a supply shortage declaration to initiate rolling outages.[35]

67. If, after an OCC is called, storage recovers above the higher of an 8% risk of future shortage and the Emergency CSRB including a buffer then the OCC ends (or it can end as otherwise agreed

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33 The sum of all contingent hydro storage and a 50 GWh buffer is also referred to as the floor associated with the Alert contingent storage release boundary (CSRB). It is needed as sometimes the calculated percentage risk is lower than the total amount of contingent storage. Floors are used to set minimum hydro storage levels for the Alert and Emergency curves (and the CSRBs), to ensure the contingent storage can be accessed when needed.

34 The sum of Emergency contingent hydro storage and a 50 GWh buffer is also referred to as the floor associated with the Emergency CSRB.

35 Clause 3.6 of the System Operator Rolling Outage Plan.

with the Authority). The Electricity Risk Meter status is set to Alert if actual storage is still below the Alert curve.

68. The 1% risk curve has been crossed in 2017 with near crossings in 2012, 2019 and 2021. In each of these cases rain arrived, and together with an industry response hydro storage never crossed the Alert curve (or the lower Emergency curve). Contingent storage has never been accessed for generation, there has not been an OCC since the regulatory framework for them was setup in April 2011, and our records indicate that rolling outages have not been needed in New Zealand since the 1970s.[36]

69. While the 1% risk curve wasn't crossed in 2024, due to the unique combination of operating conditions at the time, including rapidly declining storage levels in some key controlled storage lakes, we initiated our Watch status activities and consulted on bringing forward access to contingent storage if needed. The rain arrived before this point was reached. This system has therefore served New Zealand well to date.

3.4 Energy security outlook communications

70. This section has covered how the SOSFIP and broader market is structured to manage security of supply in Aotearoa New Zealand. The purpose of this Review is to assess whether amendments to the SOSFIP are needed to ensure this framework is fit for purpose given the changing supply mix, fuel availability and reliance on the power system in a fully electrified future. This includes considering potential amendments to the analytical approaches and assumptions we must use to determine the ERCs and SSTs. The combination of the ERCs and SSTs is the primary analytical tool we use to assess the energy security outlook for the Aotearoa New Zealand electricity system into the next 2 years.

71. Key publications we use to communicate the information and insights indicated by the ERCs and SSTs are our at least monthly Energy Security Outlook updates, and our Quarterly Security of Supply Outlook.

72. We welcome any feedback you may have about these publications, and any suggestions you may have about how we could make the insights and information indicated by the ERCs and SSTs more useful and accessible in future.

Question 3

Do you have any feedback on our Energy Security Outlook and/or Quarterly Security of Supply Outlook communications? This may include suggestions about how we could make them more useful and accessible in future.

36 New Zealanders were asked to conserve power due to low hydro storage levels prior to 2010, in 2001, 2003 and 2008. In 1992 there were non-voluntary brown-outs as network companies voluntarily turned off loads like hot water, streetlights etc to conserve hydro storage.

4 Review of key ERC and SST assumptions

73. The ERCs and SSTs (collectively referred to as the **Energy Security Outlook**)[37] are underpinned by some key assumptions to inform industry participants of security of supply risks.

74. Our Issues Paper consultation raised the potential need to review some of the assumptions as part of ensuring our Energy Security Outlook updates remain fit-for-purpose into the future. This section presents our draft proposals in relation to the following key ERC and SST assumptions topics:

- Thermal fuels assumptions: physical capability vs contract quantities
- Assumptions for worst case “time-to” when determining the time-to Alert and Emergency
- Triggering “Watch” ahead of “Alert” status
- Minimum time under Alert

4.1 Thermal fuels assumptions: physical capability vs contract quantities

75. The current SOSFIP assumes thermal power stations can run unconstrained by fuel supply limits, unless the System Operator has reliable information that limits exist. We obtain the information needed to reflect these assumptions from thermal generators (confidentially). If there are fuel limits, we reduce (derate) generation capability in line with the thermal fuel validation methodology.[38]

76. Part of this thermal fuel validation methodology is estimating the amount of gas available for electricity generation. The current SOSFIP allows for some contracted gas demand response from industrial users to be included. This is referred as Type 1 and Type 2 response. A Type 1 response is where gas is made available for electricity generation due to industrial process reducing its gas consumption and a “formal agreement” is not needed. A Type 2 response is the same but where a formal agreement is needed before it could be included in the SOSFIP. The SOSFIP specifies the thresholds of gas demand response (which is made available for electricity) that can be included for each. As an example, under the current SOSFIP, a Type 1 response up to 20 TJ/day can be used without the System Operator needing to see a contract.

77. The introduction of the Type 1 response meant that industrial gas demand response could be included in the calculation of the risk curves, up to a limit as specified in the SOSFIP. A formal agreement is needed before larger quantities of industrial gas response (Type 2) could be included in the calculation of the risk curves.

78. Type 1 and Type 2 response assumptions will no longer be needed if the System Operator performs a full contracted view of the risk and has the ability to collect contracted gas information (which will continue if the Authority’s urgent Code amendment is made permanent).[39]

79. This physical capability model in effect assumes the market acts to mitigate risk by converging towards thermal generation contributing at its maximum capability during an extended dry period. We saw this happen in both 2024 and 2025. When hydro lake levels dropped after a

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37 Energy Security Outlook | Transpower

38 See Section 6.2.1. of the Energy Security Outlook 101 which discusses the thermal fuel validation methodology.

39 Provision_of_information_to_system_operator_-_Gazette_notice.pdf

long period of low inflows, wholesale electricity prices rose sharply as hydro generators held back water. The higher prices encouraged thermal generators to run more, which meant they needed to buy more fuel - including importing extra coal and purchasing gas from industrial users.

80. We think the main principles of the physical capability model of the ERCs and SSTs remain sound, as long as the spot market provides the right price signals to reflect the higher risks. However, there is limited visibility of the gap between the modelled physical capability of thermal generators to contribute to the power system, and the capability that market participants have contracted to provide.

81. Figure 3 and Figure 4 below show the ERCs and SSTs for May 2025 calculated based on thermal fuels physical capability (the status quo) and using contracted quantities respectively. Figure 5 shows the ERCs using both methods (physical and contracted) to more clearly illustrate the differences.

82. In the short-term the two approaches result in similar projected risk positions, shown at point A in early July 2025. Earlier in the year, winter 2025 energy risk had been signalled as relatively high due to record low inflows and low gas production forecasts. Consequently, participants contracted ahead of time at close to physical capabilities, which ensured thermal fuels were available to maintain security of supply into and through winter.

83. Further ahead in time the differences between the two approaches become increasingly clear. This reflects that thermal fuels contracting activity builds up over time including in response to projected risks. For example, contracting additional thermal fuel supplies can reduce risk for periods indicated by B and D that show heightened risk in the contracted position scenario (Figure 4) versus the physical capability scenario (Figure 3).

84. We think the contracted positions model will, further ahead of time, be a less reliable indicator of how participants will coordinate a market response to mitigate energy risks as they unfold. In part this reflects that thermal fuel supply commitments are built up over time as contractual arrangements are negotiated and renegotiated. Further, a heightened risk of an extended dry period leading to potential hydro shortage unfolds over the weeks and months ahead. When this happens, we would expect the response from participants to include contracting to secure more nearer-term thermal fuel supplies. It would also be useful to highlight and understand if this convergence does not occur.

85. Consequently, we expect ERCs and SSTs based on contract quantities to shift a lot more with each update than for the physical capability model. We also expect greater convergence between the two models to be more likely to occur at times of nearer-term heightened risk than further into the future.

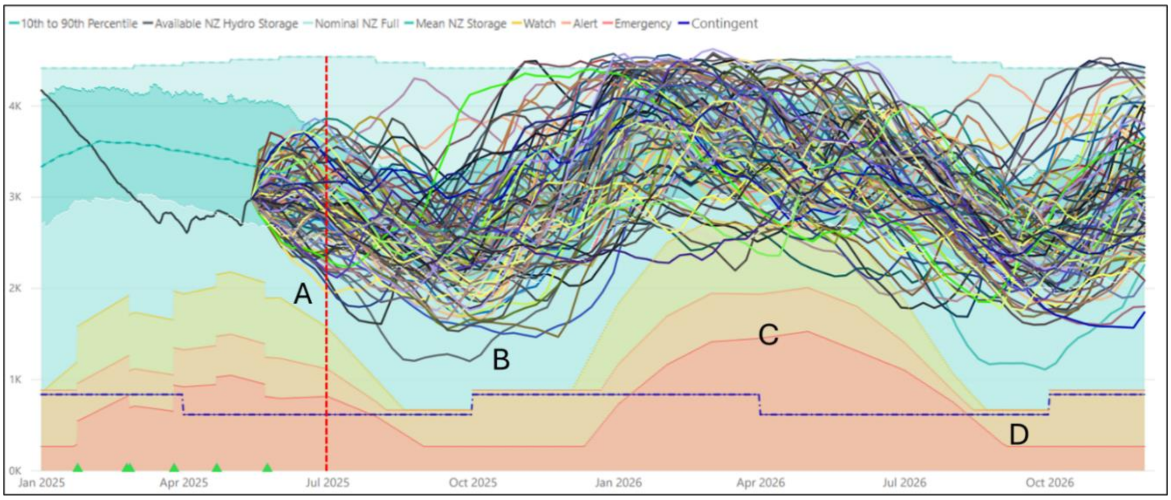

Figure 3: Status quo ERCs and SST for May 2025

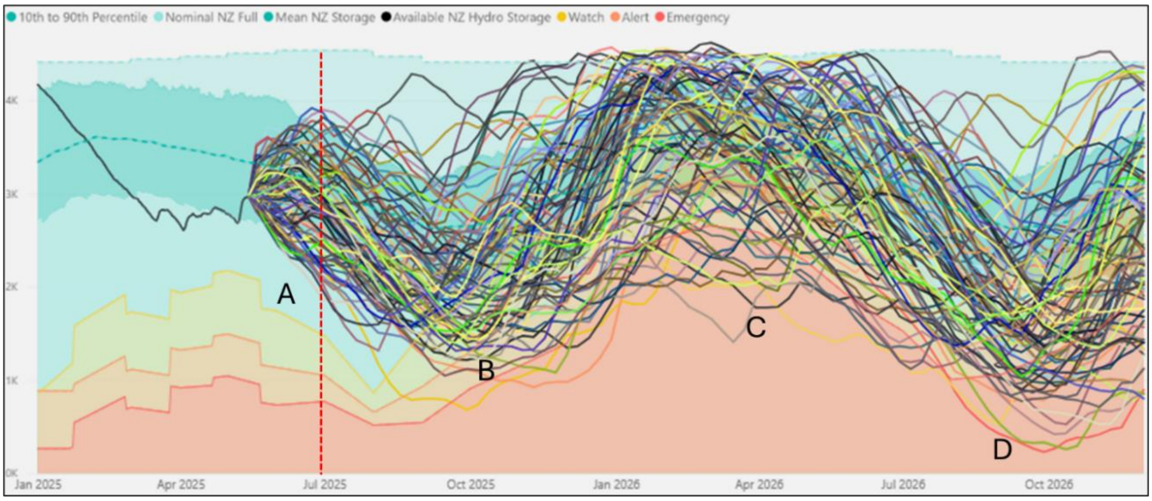

Figure 4: ERCs and SST for May 2025 based on contracted quantities

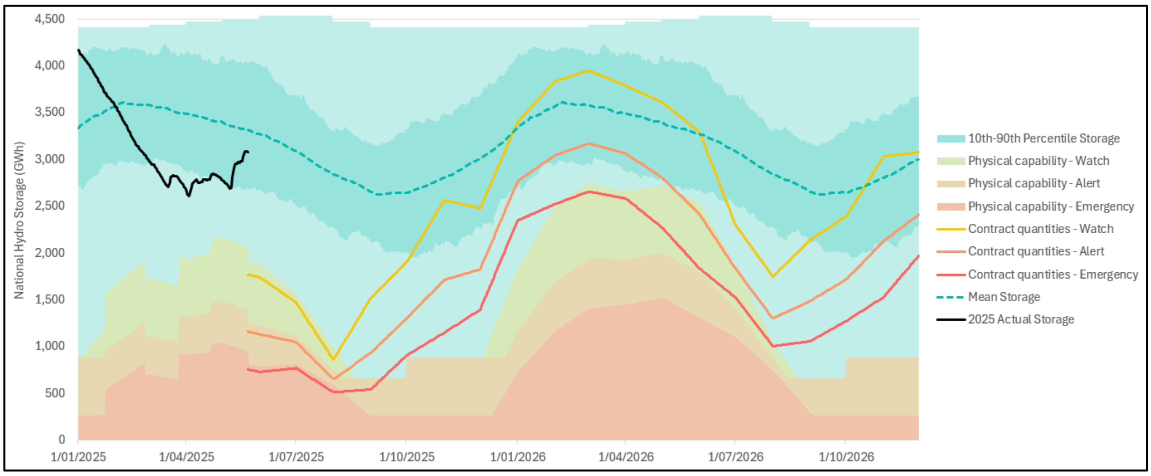

Figure 5: May 2025 ERCs based on physical capability (status quo) and contract quantities

86. More transparent information about the gap between the physical capability of the system to source thermal fuels and the extent to which participants have contracted to do so can support

better understanding for participants and stakeholders about future energy risks by providing visibility of the:

- Extent to which participants have already contracted for thermal fuel supplies
- Remaining potential to source additional thermal fuel supplies, and
- Balance of risk that may need to be addressed through other capabilities such as controlled hydro storage management and industrial demand response.

87. The potential drawbacks of providing both the physical capability model and the contracted position model for thermal fuels with each update include:

- Information about projected energy risks could change significantly between updates as contracted position change. We explain the reasons for notable shifts in our published Energy Security Outlook materials each month and expect this to include commentary about thermal fuel contract position shifts going forward.
- Projected energy risks using contracted fuels information will be less reliable further out. Consequently, our current thinking is the time horizon for ERCs and SSTs reflecting thermal fuel contracts should be limited to 12 months ahead. However, this might come with drawbacks such as missed opportunities to accelerate new generation investment decisions, or supporting understanding of the extent to which longer-term thermal fuel arrangements are already in place.

88. The System Operator will incur additional effort and cost in data collection/processing and producing the ERCs and SSTs with each update.

System Operator proposal

89. Our proposal is to:

- Introduce a requirement to publish ERCs and SSTs reflecting contracted thermal fuel that can be used for electricity generation (in addition to the ERCs and SSTs we publish currently which reflect physical capability).
- Continue to set the Electricity Risk Meter status and any of the actions triggered by the ERCs from the physical capability ERCs (only).
- Remove the Type 1 and Type 2 gas demand response assumptions and related definitions.

90. Our proposed changes to the SOSFIP (to the extent changes are required) are in clauses 2.1, 6.1(aa), 6.1(ac), 6.1AA and 12.1A of the SOSFIP in Appendix 1.

91. We also propose to update the thermal fuel validation methodology in the System Operator's Energy Security Outlook 101 to include ERCs and SSTs reflecting contracted thermal fuel that can be used for electricity generation.

92. Taking this potential SOSFIP amendment forward requires the System Operator to have the ongoing ability to require participants to provide contracted thermal fuel information (confidentially). Earlier in 2025 the Authority approved an urgent Code amendment[40] that has enabled us to source this information confidentially from participants, and it has recently consulted on a proposal to make that amendment permanent.[41]

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40 Provision_of_information_to_system_operator_-_Gazette_notice.pdf

41 Review of urgent Code amendment to System Operator's information gathering powers | Our consultations | Our projects | Electricity Authority

Question 4

Do you agree that introducing an additional ERC and SST scenario using contracted fuel information to our Energy Security Outlooks would better support understanding about forward energy risks, and mitigating actions by participants? This scenario would be in addition to continuing to provide the current physical capability scenario. Please provide your reasons.

Question 5

How far into the future do you think any contracted fuel information scenario should be modelled? This could be any duration up to the full length of the physical capability scenario, which is up to 24 months. Please explain your rationale.

4.2 Time-to SST

93. When actual hydro storage crosses the Watch curve (whether nationally or in the South Island), the System Operator is required to estimate the "time-to" Alert and an OCC and will make public the methodology used to derive this estimate.[42] The method we use to calculate the worst-case SST for this purpose is explained in our Energy Security Outlook 101 document (section 9.4).[43]

94. Currently, we use a "worst-case SST" as the basis for the estimated time-to Alert, OCC and as part of our contingent storage release boundary (CSRB) buffer discretion process. The worst-case SST is calculated by combining the lowest inflow on record for each week of the year in sequence into a synthetic, worst-of-the-worst inflows sequence.[44] Figure 6 below shows the worst-case SST (red line) and illustrates how it is used to estimate the time-to Alert (A) and a potential OCC (B[45]). While the system is at Watch status we recalculate and publish the worst-case SST and the time-to metrics each business day.

95. The rationale for using a "worst-case" approach to determine the estimated "time-to" Alert and OCC is that it provides an estimate of the minimum time remaining before Alert and OCC could be triggered, and therefore the minimum amount of time available for cross-industry preparation.

42 See clause 4.1(b) of the Emergency Management Policy.

43 See Clause 4.1(b) in the Emergency Management Policy

44 Energy Security Outlook 101.pdf

45 Note this is 7 days after crossing the Emergency curve as an OCC can be triggered if there is a risk of storage remaining below the Emergency curve for at least a week. See clause 9.23 of the Code.

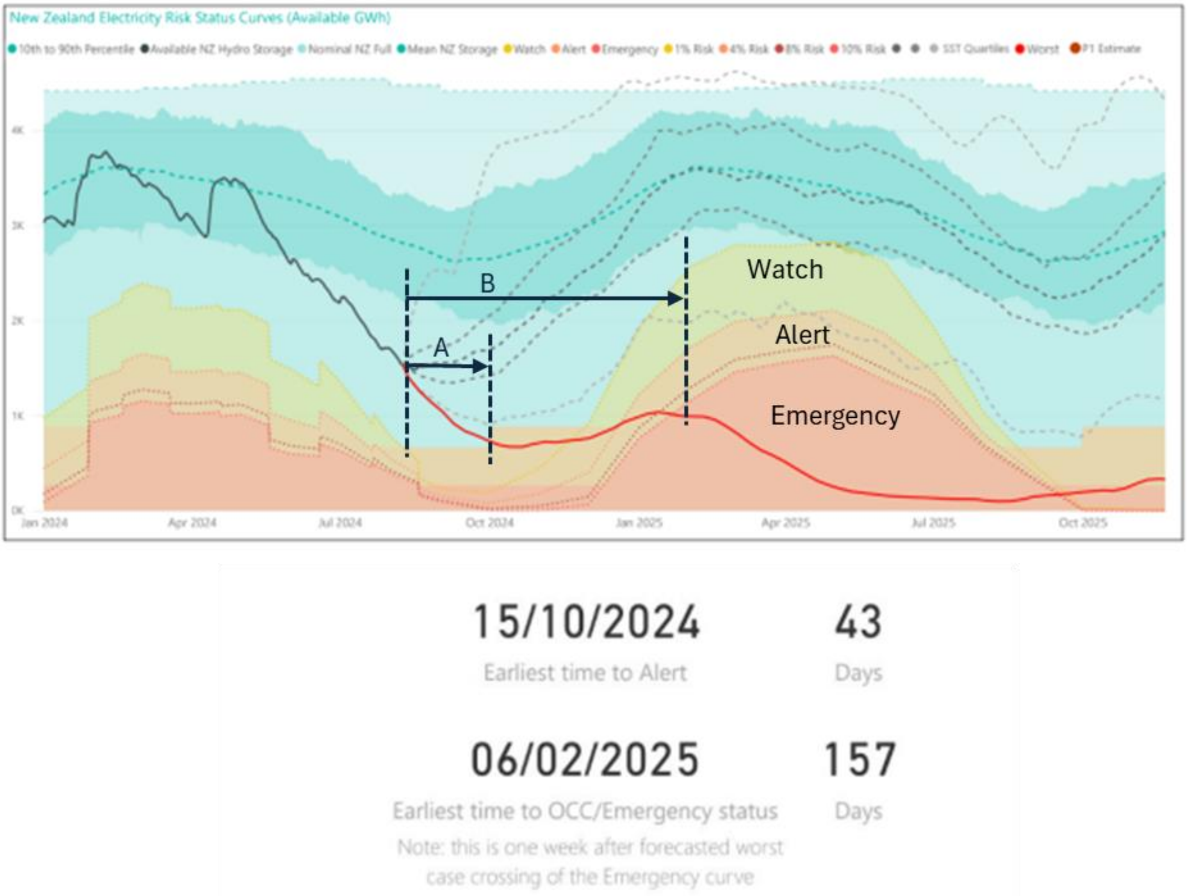

Figure 6: Worst-case SST with "time-to" estimates based on the worst-case SST

96. Following the low hydro situation in 2024, participants raised concerns about the basis of the worst-case SST. Primarily that it's too pessimistic a projection of potential worst-case inflows, especially when looking further into the future.

97. We consider there is merit to this perspective. While it is believable that an extended dry period (based on worst-case inflows) could continue to persist for the coming weeks, it is much less believable that it will continue to persist months into the future. We think that while the current methodology for calculating the worst-case SST is helpful near term, it becomes increasingly less useful further into the future. Consequently, we raised this as a potential review topic in our Issues Paper. The feedback we received confirmed general alignment on the need to reconsider the approach to calculating the worst-case SST.

98. We think an alternative approach, that is likely to result in a more realistic indication of how soon Alert status or OCC could be triggered, would be as follows:

- Using inflow records for the corresponding week, calculate a "time-to SST" using:
  - Weeks 1 to 4: the 1st lowest weekly inflows
  - Weeks 5 to 8: the 3rd lowest weekly inflows
  - Weeks 9 to 12: the 5th lowest weekly inflows
  - Weeks 13+: the 10th lowest weekly inflows

99. The chart below shows a comparison of the current worst-case SST (red) and our proposed time-to SST (orange). Both these estimates are more pessimistic than the SST range using

historical inflows (blue shaded area) with the time-to SST being less pessimistic than the current worst-case SST further into the future.[46]

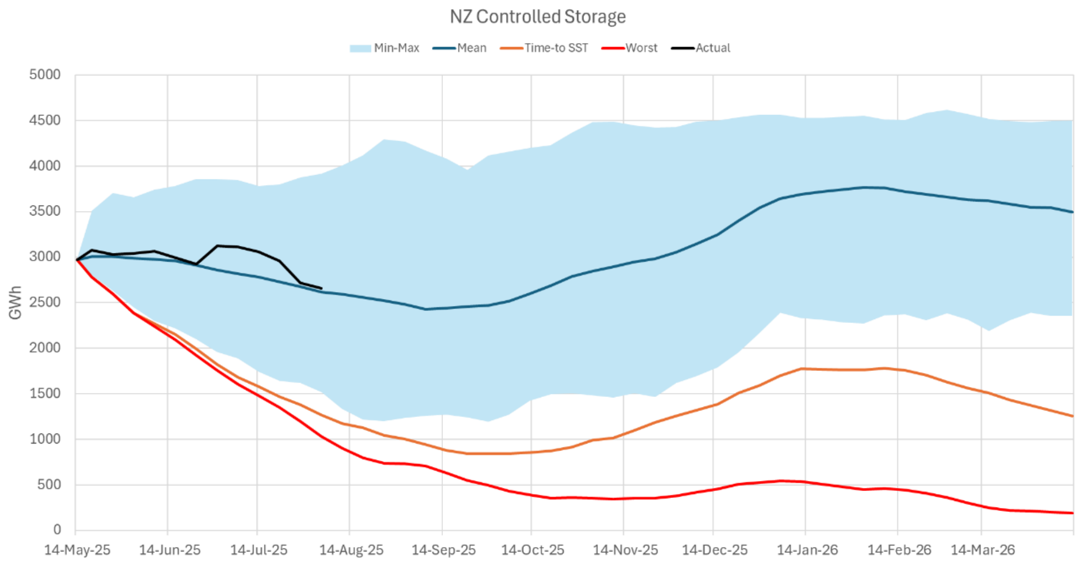

Figure 7: Current worst-case SST compared to proposed time-to SST

100. A key benefit of the proposed time-to SST is that it is less conservative than the current worst-case SST approach for simulated periods further into the future. This will help improve the "plausibility" of these "time-to" estimates the further out in the future.

101. A potential drawback is that a drier sequence of inflows than modelled could occur with the result that the time-to-reach Alert and/or an OCC turns out to be less than had been estimated. We don't think the risk of this occurring is significantly greater for the proposed time-to SST than it is for the current worst-case SST because both methods are the same for the next four weeks. Also, at Watch status, an estimate of the "time-to" Alert status and an OCC will be updated and published every business day by the System Operator. This will ensure an ongoing constant focus on, and tracking of, actual storage versus the time-to SST that is transparent to participants and other stakeholders.

System Operator proposal

102. We propose to adopt the proposed time-to SST calculated as set out in paragraph 98 for the purpose of estimating the time-to Alert and OCC. This will also be used as part of our CSRB buffer discretion process.

103. We propose to give effect to this approach by updating the System Operator's Energy Security Outlook 101.[47] This change does not require any changes to the SOSFIP.

46 The actual storage (black) is tracking along the mean simulated storage trajectory (blue).
47 See Energy Security Outlook 101.pdf, section 9.4.

Question 6

Do you agree with our proposal to replace the current worst-case SST with a time-to SST that is progressively less pessimistic into the future? Note the time-to SST will be used to determine the estimated time-to for Alert, OCC and as part of our CSRB buffer discretion process? Please provide reasons for your answer.

4.3 Triggering Watch before Alert

104. When actual controlled hydro storage drops below the Watch curve (1% risk curve), the System Operator increases its reporting to the market on security of supply risks, including by calculating and publishing estimated "time-to" Alert and "time-to" OCC each business day (as described in Section 4.2). This provides better information and as much time as possible that supports participants to resolve security of supply through a market response (i.e. reduce the rate of hydro storage decline until it starts to rain). If a market response does not sufficiently resolve the situation, or more time is needed before it rains, then the System Operator must step in to trigger non-market mechanisms (access to contingent storage, an OCC and rolling outages).

105. The SOSFIP sets out how the System Operator must calculate the electricity risk curves, including the Watch and Alert curves as follows:

- The Watch curve is required to be the 1% electricity risk curve (definition of 'watch status curve')
- The Alert curve is required to be the 4% electricity risk curve (definition of 'alert status curve')
- If an electricity risk curve is a contingent storage release boundary then the risk curve calculation includes a floor set reflecting the total amount of contingent hydro storage across the system plus a buffer (clause 6.1A).

106. Currently, the Alert risk curve is a contingent storage release boundary but the Watch curve is not. The floor typically sets the Alert curve in late winter and early spring as shown by the flat sections (floor) in the Alert curve in Figure 8. When this happens, Alert status can be reached without having previously entered Watch status. This has the consequence that participants may not have had the benefit of increased information and time to prepare before Alert status is triggered. It was a factor behind our decision to bring forward Watch status activities in August 2024.

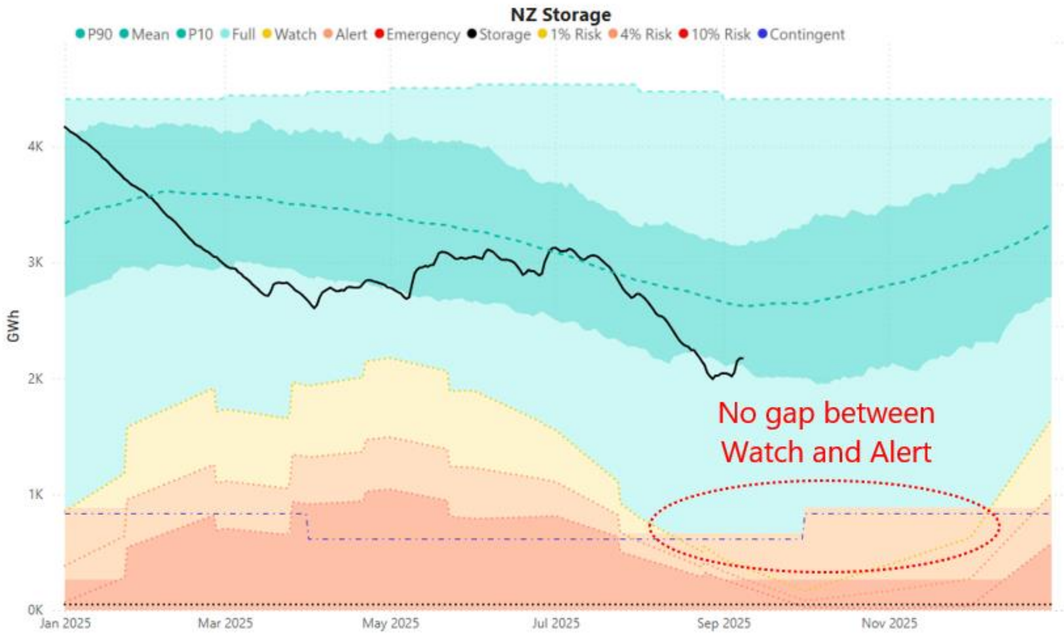

Figure 8: NZ storage and ERCs showing Alert floors (set by contingent storage and buffer)

107. While we do have the ability to decide to begin Watch status activities ahead of storage crossing the Watch curve (and Electricity Risk Meter Status being set to Watch), we consider having a clearer boundary between Watch and Alert would provide more certainty and better information to market participants.

108. We propose to amend the method we use to calculate the Watch curve so that, for each simulation month, we apply an adder above the Alert curve (the Watch adder). We have considered two options:

- Option 1: Apply a 200 GWh adder above the Alert curve (the Watch adder), with this default Watch adder increased (not decreased) if necessary to match the simulated future storage projections (used to determine the ERCs) with the biggest drop across its first month.
- Option 2: Apply a fixed 200 GWh adder above the Alert curve (the Watch adder).

109. Option 1 utilises analysis we already do for each Energy Security Outlook update. Our Energy Security Outlook 101 document provides an overview of how the electricity risk curves are simulated, as follows:[48]

> *52. The ERCs are calculated using a hydro-thermal scheduling model to simulate operation of the current power system day-by-day and a range of input assumptions regarding the next 12-24 months …. The model uses each historic calendar-year inflow sequence since 1931 to estimate a range of future storage level possibilities. The model is based on the underlying assumption that the market is acting to conserve hydro storage in an emergency. That is, by securing additional fuels that are available, cancelling outages where possible and thus, conserving hydro storage as much as the system enables.*

48 Energy Security Outlook 101.pdf, section 4.1.

53. *Potential future storage is calculated for each historic inflow sequence since 1931, to create a range of possible future storage scenarios. These future storage values are then used to determine the ERCs. The 1% ERC is the point at which 1% of the future storage projections would run out of hydro storage within the next 12 months. The 10% ERC represents when 10% would run out. [Here is a series of videos](#) which provides a simple visualisation of the calculation.*

110. The Watch, Alert and Emergency ERCs are built up by simulating the wider set of ERCs month-by-month and adjusting the starting storage level for each simulation month to the point at which 1%, 4% and 10% (respectively) of the individual simulated ERCs would result in controlled hydro storage running out.[49]

111. Figure 6 shows the May 2025 simulation month future storage projections that set the basis of our May 2025 ERCs.[50]

112. Using Option 1 the Watch adder for the May 2025 simulation month would be set by the greater of:

- GWh represented as difference between A to B which represents the greatest drop of the simulated future storage projections for the May 2025 simulation month ERC
- 200 GWh

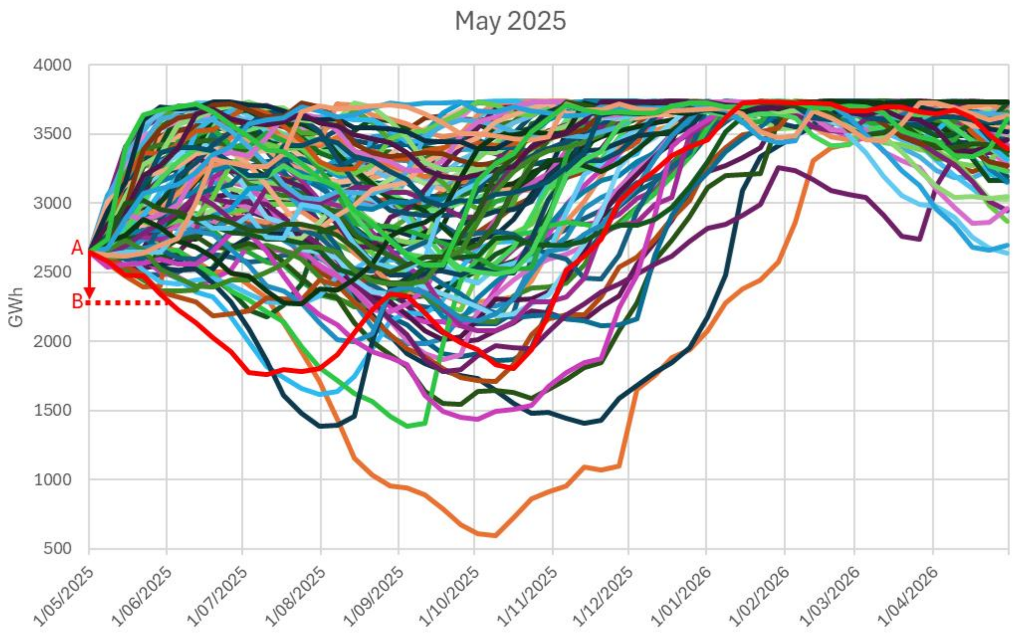

Figure 9: Worst ERC simulation reduction for May

113. During some periods of the year (such as during spring) inflows are typically expected to increase[51] and there is an expected increase in hydro storage, especially if hydro generation is also minimised as it is in the ERC calculation. This is shown in Figure 9 with B being greater than A for the May 2025 Energy Security Outlook's December 2025 simulation month. This means the drop in hydro storage cannot always be used and a default minimum difference between

49 Refer to Energy Security Outlook 101.pdf, section 4.3.3 for a more detailed explanation.

50 Energy Security Outlook - May 2025.pdf

51 In spring we typically get increased inflows due to snowmelt.

Watch and Alert is also needed. This is why we propose that the Watch curve calculation include a default minimum hydro storage drop across the first month (the Watch adder).

114. We think the Watch adder should initially be set at 200 GWh, which corresponds to the average drop in storage over a 1-month period when storage is below 80% of mean. We also think the System Operator should have a discretion in the SOSFIP that allows it to set a different adder if doing so would better align the Watch and Alert curves with observed system conditions at the time.

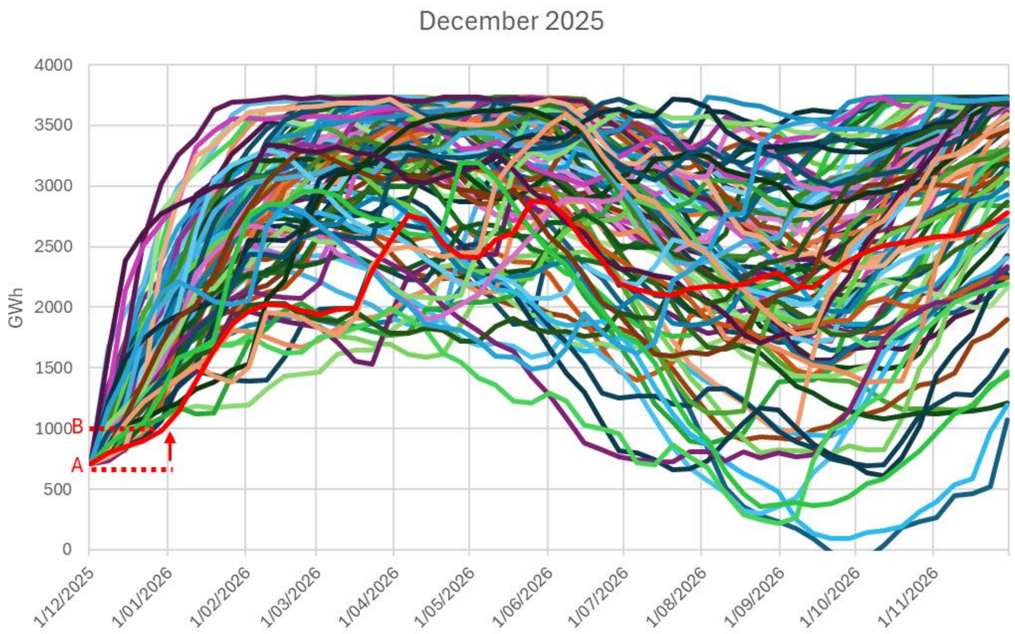

Figure 10: Worst ERC simulation reduction for December

115. Option 2 considers a Watch curve that only uses a fixed 200 GWh Watch adder above the Alert curve.

116. The figures below show the impact on the ERCs for each of the options.

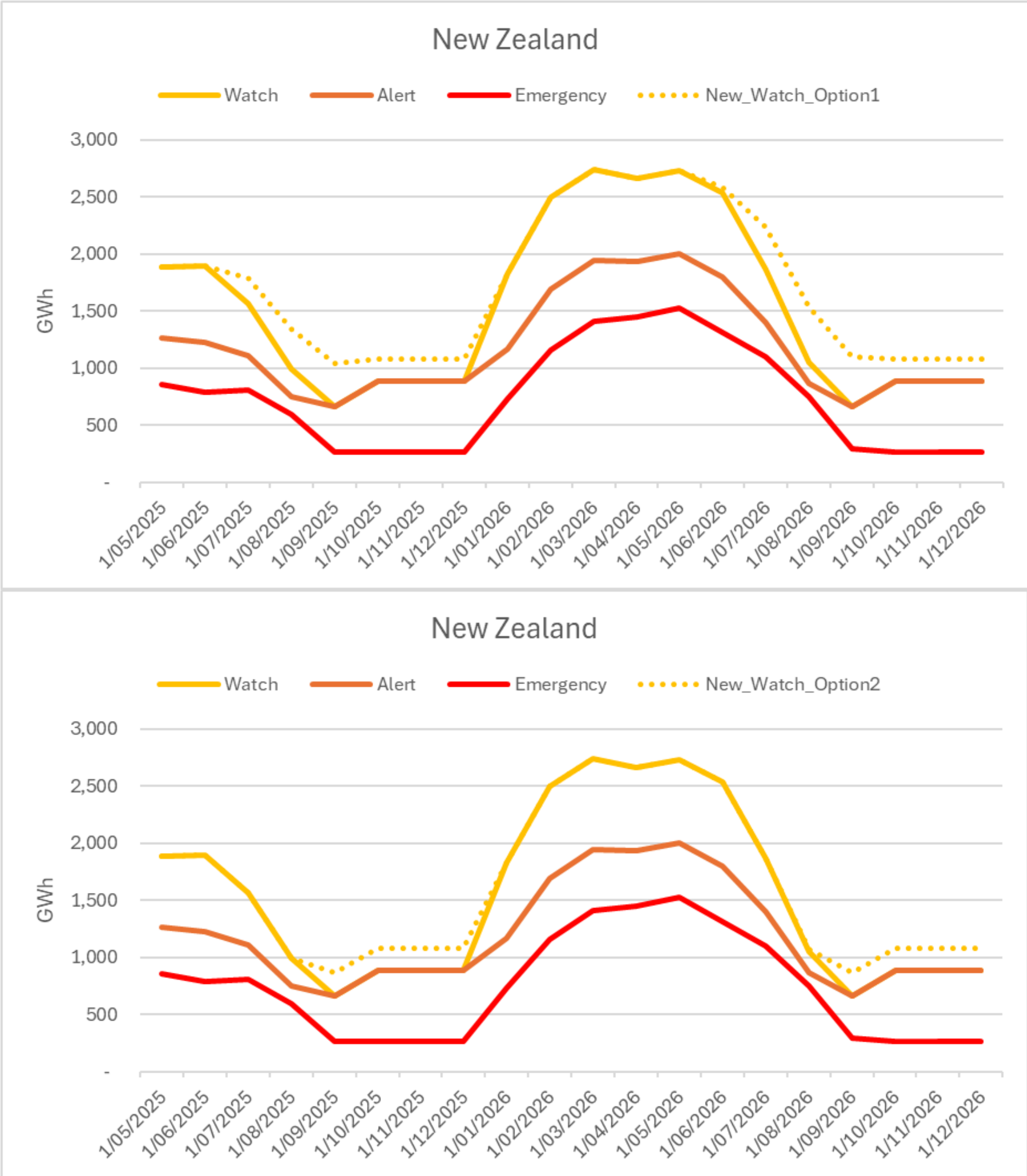

Figure 11: Options for increasing Watch above Alert

117. The key benefits and drawbacks we have considered for each of these options are shown in the table below. While Option 1 is less simple than Option 2, we consider implementation costs for both options are not material, and ongoing operational requirements are comparable to the current situation.

	Option 1	**Option 2**
Benefit	Watch curve triggered ahead of Alert using a risk-based adjustment. Using the worst-case storage drop from the ERC simulations for the first 4 weeks means a higher adjustment is used when there is an increased risk of rapid storage decline (e.g. if there is less thermal back-up generation such as a major outage).	Setting a fixed trigger level is simpler to implement

	Option 1	Option 2
	Uses data we currently use as part of the ERC calculation.	
Drawback	There could be a perceived increase in complexity. However, none of the information used is new and the data used is also being used for the ERC calculation. As with the current approach with recalculating the ERCs (including the Watch curve) each month based on updated information, there could be a scenario where with updated inputs, the Watch curve increases to such an extent that actual storage is below the most recent calculated Watch curve. We propose to mitigate this risk by setting a default minimum hydro storage drop across the first 4 weeks of 200 GWh (the Watch adder).	While Option 2 is simpler, it has a higher degree of non-triggering because the trigger level is decoupled from the risk level. This would reduce the effectiveness of, and confidence in, the trigger if Watch activities are not triggered at times when the observed system conditions and security of supply outlook do not align with that outcome.

System Operator proposal

118. On balance we think Option 1 is preferable to:

- the status quo because it would ensure Watch status is triggered before Alert; and
- to Option 2, which would decouple Watch status from observed risks at the time.

119. Our proposed changes to the SOSFIP to give effect to Option 1 are in clause 2.1 of the SOSFIP in Appendix 1 (definitions of “watch adder” and “watch status curve”).

Question 7

Do you agree with the proposal to update the definition of the Watch curve to ensure Watch is always above the Alert curve, and our preference for Option 1? If not, please provide reasons for your answers.

4.4 Minimum time under Alert status

120. Participants have raised the risks associated with triggering Alert status and access to contingent storage being granted only for inflows and storage in some lakes to quickly increase and Alert status end. The uncertain nature of future inflows means the current Alert trigger could “flip-flop” between Alert and Normal risk states.[52] For the generators this increases uncertainty about the duration of the Alert status and whether Alert contingent storage can or should be accessed in practice.

121. An option to address this issue, is for the Alert status, once activated, to remain active for at least 4 weeks, unless storage increases above the Watch curve before then or the risk meter

52 This situation is avoided under an OCC with the 10% risk curve being one of the triggers for entering into an OCC but the 8% risk curve being used as a trigger to exit.

status moves into Emergency. This will reduce the uncertainty of remaining in an Alert risk meter status.

122. Another option is to create an additional risk curve (an "Alert exit" curve between Watch and Alert) which could be used as an exit for the Alert status. This option is not guaranteed to address the certainty raised by participants as the "Alert exit" risk curve could potentially be close to the Alert curve. Furthermore, the introduction of another risk curve could increase complexity and would increase implementation costs. For these reasons we did not prefer this option.

System Operator proposal

123. Our proposed changes to the SOSFIP are in clauses 7A.2 and 7A.5 of the SOSFIP in Appendix 1.

Question 8

Do you agree with the proposal to have a minimum time under Alert of 4 weeks to reduce the uncertainty? If not, please provide reasons for your answers.

5 Linkage between energy and capacity risks

124. Feedback to our Issues Paper consultation highlighted the need for greater clarity about how we assess both energy and capacity risks that may trigger access to contingent storage.

125. The ERCs and SSTs, reported in our Energy Security Outlook updates, work together to signal forward exposure to key energy risks such as variations in hydro inflows variability and the capability of thermal generation assets and fuel supplies. Calculating the ERCs and SSTs involves detailed hydro-thermal modelling based on historic inflow sequences, wind and solar profiles and reflecting the current power system (including generation assets, fuel supplies, the transmission grid and forecast demand) up to three years into the future. The Alert ERC is the trigger for access to contingent storage, with an additional tranche of contingent storage available at Emergency status.

126. As set out in section 3.1 above, the primary sources of information we use to signal and coordinate capacity risks are the annual SOSA (10 years ahead), NZGB (200 days ahead) and our Low Residual Situation process (week-ahead). Our regular Quarterly Security of Supply Outlooks and fortnightly System Operator Industry Forums provide regular updates about capacity risks.

127. Energy risks can also result in capacity risks, as was the case in 2024. Our August 2024 decision to bring forward access to contingent storage was to mitigate the risk that the power system may not have been able to meet peak demand during a spring cold snap should both the Waitaki and Clutha generation schemes be unable to flex up. This could have occurred if the storage lakes had reached the boundary of contingent storage without actual aggregate hydro storage having crossed the Alert ERC. In this situation river flows are required to be held to inflows and the ability of the generators to flex up to meet intra-day peak demand is compromised.

5.1 Improving capacity risk assessment in the ERCs and SSTs

128. To reduce the solve times for this modelling but still capture the energy risks, a day-night representation of the load profile is used which allows for fewer variables to be used in the model. By using a day-night model, the load shape and peak load periods are averaged down, reducing the ability to inherently reflect capacity risks within signalled energy risks.

129. Changing our ERC and SST models to a 3-hour representation would allow more granular representation of the load profile in the day, and at peak. This approach would help capture more capacity related issues within the ERCs and SSTs. We propose to make this change.

130. Figure 12 below summarises the results of our initial testing of the difference between the current day-night model and the proposed 3-hour model. It shows that the modelled energy risk using the each of two methods is very similar. The 3-hour model (dotted lines) indicates a slightly higher risk than the current day-night model (solid lines).

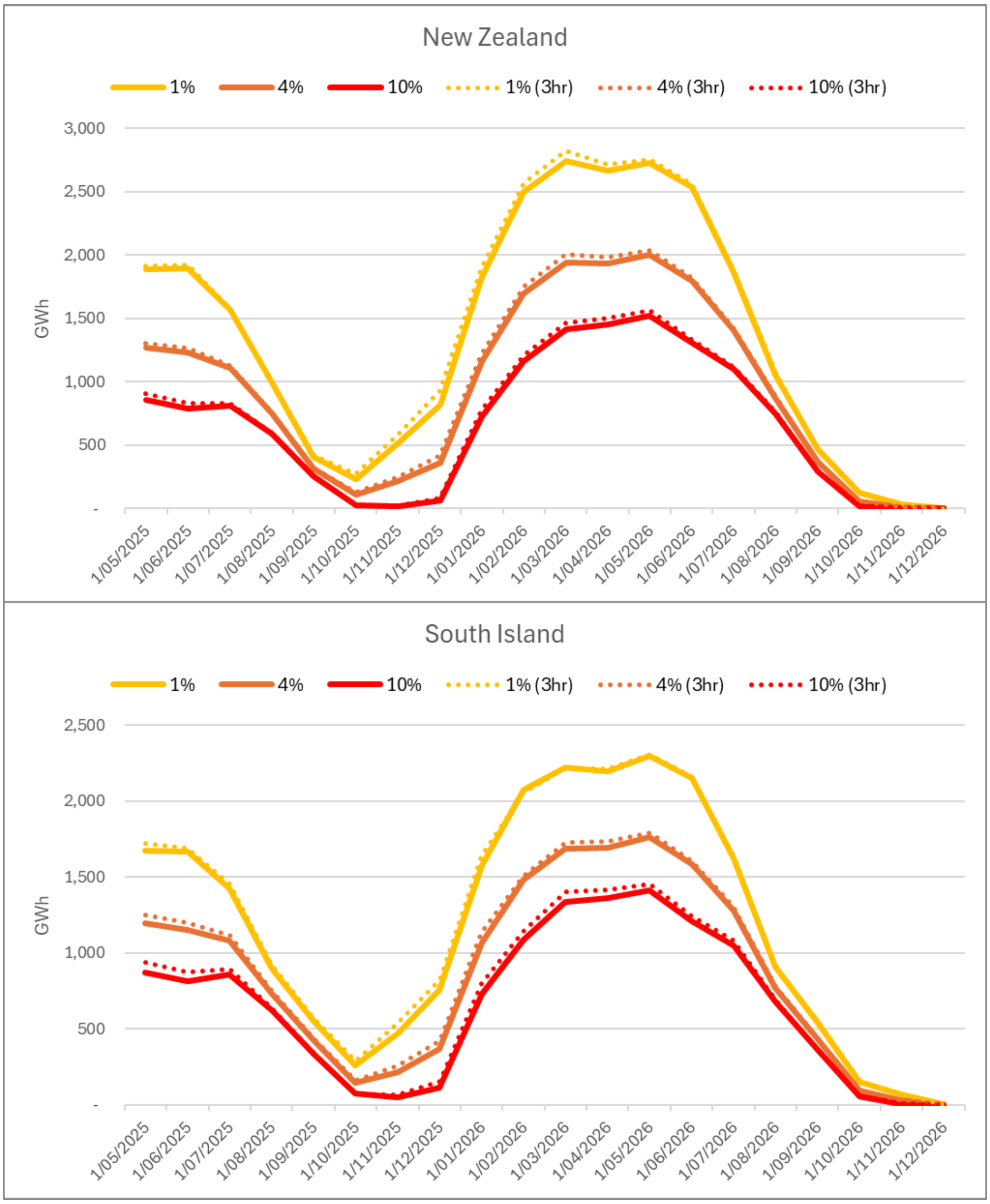

Figure 12: ERC with current day-night versus 3-hour modelling

131. Implementing these changes does not require any updates to the SOSFIP. At this stage we do not expect to incur any material costs to implement the proposed approach. However, any material one-off or ongoing implementation costs incurred by the System Operator would need to be funded by the Authority.

System Operator proposal

132. We propose to amend our ERCs and SSTs tools and analysis to a 3-hourly model (rather than the current day-night model). This change does not require any changes to the SOSFIP.

Question 9

Do you agree with the proposal to change our ERCs and SSTs tools and analysis to a 3-hour model (rather than the current day-night model)? If not, please provide reasons for your answers.

5.2 Using supplementary information to enhance capacity risk indications

133. The System Operator uses NZGB as a key indicator of potential capacity risks over the next 200 days. NZGB is updated daily as participants upload new outage information. Within a week of real-time, the market schedules (WDS, NRS, PRS and RTD) are used to assess peak capacity risks.

134. NZGB includes the effect of planned generator outages, transmission outages that impact generation, reserve requirements, peak load scenarios, generation scenarios, and unplanned outages. These are all important factors impacting the peak capacity risk.

135. While it is possible to improve the capacity risk modelling in the ERCs and SSTs, it is impractical to rely on any single assessment (modelling tool) to cover all of the energy and capacity related risks across the system. This is due to the complexity of the modelling that would be required (e.g. taking into account outage risks, load variations, wind variation risks). This complexity would also make it hard for us and participants to take useful insights from the modelling results.

136. We will continue using NZGB for our assessment of peak capacity risks outside of the market schedule horizon. However, we consider there are some enhancements we can use to increase alignment between NZGB and our Energy Security Outlook (ERCs and SSTs) energy risk assessments. These include:

- Providing additional NZGB scenarios to reflect capacity constraints on hydro schemes as they approach their lower operating range of storage
- Extending the NZGB assessment horizon to provide a rolling 12-month capacity risk assessment
- Including a capacity risk assessment (using NZGB) as part of the monthly Energy Security Outlook, based on the capacity snapshot as at the time, and commentary on the implications of each on the other. As an example, if we are highlighting periods of increased energy risk in the Energy Security Outlook we should also be focussing on this as part of the capacity risk assessment.

137. Implementing these changes does not require any updates to the SOSFIP. However, it would require investment to be made in our NZGB tools, which we currently consider might be of the order of $50k-$100k. The feedback we receive in response to this consultation will inform our assessment of whether participants consider the benefits of making this investment would outweigh the likely costs. Our ability to make the changes would be contingent on receiving the funding to do so.

System Operator proposal

138. We propose to enhance our NZGB and Energy Security Outlook reporting for greater alignment by extending the NZGB time horizon, adding addition capacity scenarios to NZGB and including

capacity risk assessment (using NZGB) to Energy Security Outlooks (as discussed above). This change does not require any changes to the SOSFIP.

Question 10

Do you agree with the proposal to enhance our NZGB and Energy Security Outlook reporting for greater alignment by extending the NZGB time horizon, adding addition capacity scenarios to NZGB and including capacity risk assessment (using NZGB) to Energy Security Outlooks? If not, please provide reasons for your answers.

6 Consideration of geopolitical and asset risks

139. Feedback in response to the Issues Paper also identified a need to consider the extent to which the SOSFIP should consider the implications of the increasing influence of global geopolitical factors on energy markets and supply chain (domestic and international), particularly in relation to thermal fuel supply disruptions.

140. Currently, Part 13 of the SOSFIP requires the System Operator to develop thermal fuel supply disruption scenarios, which we do by considering the impacts of reduced thermal generation capability in our monthly Energy Security Outlooks and NZGB scenarios.

141. We propose Part 13 could be expanded to require us to consider scenarios related to both thermal fuels, and to loss of major generation and/or transmission assets for several months, such as:

- Loss of major thermal fuel supply for three months (e.g. gas field or coal imports)
- Loss of major generation asset for six months (e.g. E3P or Huntly Rankine)
- Loss of HVDC for six months

142. We consider the major benefit of widening Part 13 in this way would be to provide greater visibility of the potential impact wider risks could have on the New Zealand power system. By understanding these risks, participants can be better prepared if these (or similar) situations were to arise.

143. At this stage we do not expect to incur any material costs to implement the proposed approach. However, any material one-off or ongoing implementation costs incurred by the System Operator would need to be funded by the Authority.

System Operator proposal

144. We propose to generalise clause 13 of the SOSFIP to require us to consider scenarios related to both thermal fuels and to loss of major generation and/or transmission assets for other reasons.

145. Our proposed changes to the SOSFIP are in clause 13 of the SOSFIP in Appendix 1.

Question 11

Do you agree with the proposal to expand the systems risks for consideration as part of the quarterly scenario assessments? If not, please provide reasons for your answers.

7 Contingent storage buffer access arrangements

146. In this section we discuss the role of contingent hydro storage (its primary purpose and role in the security of supply framework), how access to contingent hydro storage is currently triggered, the role of the CSRB buffer (its default value and the discretion process) and finally the implications if there is a desire to change how contingent storage is accessed.

7.1 What is contingent storage

147. Resource consents for Lakes Pūkaki (Meridian Energy), Hāwea (Contact Energy) and Tekapo (Genesis Energy) include arrangements through which extra storage is available to generators contingent on access being necessary for national security of supply.

148. The decisions by the local authorities to make access to this water contingent on the risk to electricity security of supply – as we understand it – reflect concerns about the known and likely impacts of very low storage levels on the environment, and the communities local to the storage lakes including through downstream economic implications for industries such as tourism and agriculture. This means access to contingent storage for electricity generation is currently allowed only under exceptional/limited circumstances.[53]

149. Contingent hydro storage is therefore effectively the stored fuel of last resort for Aotearoa's power system, playing a role sometimes referred to as strategic energy reserve. It is held back through regulation,[54] to be available to respond when events and/or weather move against us. In that sense it is a form of insurance. Relative to other electricity systems worldwide its role is important. We do not have interconnection to other jurisdictions, so we cannot diversify the management of the risks inherent in renewable fuels availability/reliability across broad geographic regions. And our location in the world means lead times for onshoring importable, storable fuels (currently coal and diesel) are long (typically months). We do not import gas and our ability to store gas is limited. This situation may change in the coming years.

150. There is currently no other form of energy storage (or strategic reserve) in our power system that is held out of the market through regulation for use only when the risk of electricity shortage is sufficient to make accessing it necessary. After contingent storage has been accessed, the last tools available to protect the ability of the power system to supply consumers are OCCs and rolling outages. Both these tools would have substantive impacts for households, businesses and industries – and New Zealand, both economically and reputationally.

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53 This SOSFIP Review necessarily considers contingent storage arrangements consistent with current consent conditions. Currently, Meridian has indicated it will apply for resource consent to enable it to access contingent storage in the absence of an Alert or Official Conservation Campaign being in place, for a three-year term. It has been reported (Contact Energy seeks to dip deeper into Lake Hāwea | RNZ News) that Contact will apply to fast-track applications for resource consent to increase its access to water on a day-to-day basis, by lowering the minimum normal operating lake level to include storage that is currently contingent storage, and providing for additional water lower in the lake to be available as contingent storage. Should these consenting processes result in a change to contingent storage arrangements there may be a need to consider amendments to the SOSFIP and/or other elements of the security of supply information and forecasting framework.

54 Including the Waitaki Catchment Water Allocation Plan (**WAP**), Manapouri-Te Anau Development Act 1963, resource consents and operating rules.

151. Figure 13 shows the amount of contingent storage available in each lake across the year at each of the electricity system risk statuses (Alert and Emergency). [55]

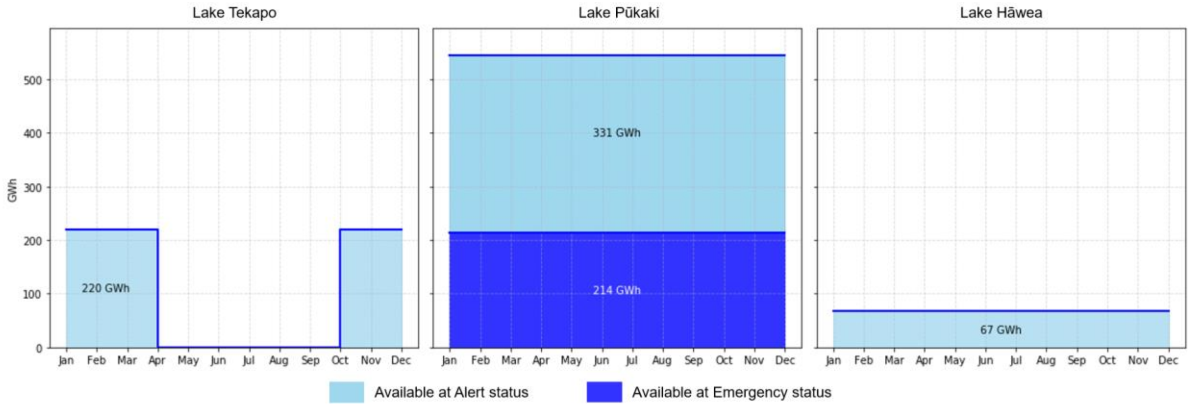

Figure 13: Contingent storage availability

152. The amount of contingent storage available under Alert status changes during the year:

- October to March (across summer): ~612 GWh of contingent storage is accessible across Pūkaki, Tekapo and Hāwea (equivalent to ~106 days of running a Huntly Rankine generator at 240 MW).
- April to September (across winter): The normal minimum operational level of Lake Tekapo is 220 GWh lower. This means during the winter there is 220 GWh more storage that can be accessed under normal operation. As a result ~398 GWh of contingent storage is available under Alert status from Lakes Pūkaki and Hāwea (~68 Rankine days).
- There is an additional ~214 GWh of contingent storage accessible in Pūkaki at Emergency status (37 days of running a Rankine generator) all year.

153. The total amount of contingent storage in the system (accessible under Alert and Emergency statuses) is included in the calculation of the ERCs and shown by the purple dashed line in Figure 2.

7.2 Access to contingent hydro storage

154. Access to contingent storage is triggered by the risk facing the system based on a clearly-articulated risk-based framework. Industry receives regular (at least monthly) updates on the current risk status of the system through the System Operator's Energy Security Outlook. As such, all participants should have the ability to factor when access to contingent storage will be triggered into their trading and wholesale market risk management decisions.[56] In this sense, accessing contingent storage is not bringing new energy to the market – it is more about how and when that access occurs based on the risks facing the system.

55 Contingent storage is specified in metres in resource consents. The conversion to GWh is based on the electrical energy potential from downstream generators. As an example, the 220 GWh at Lake Tekapo represents the total potential generation from all downstream generators. ~80 GWh of the 220 GWh of Tekapo contingent storage is generated at Tekapo A and B. The remainder (~140 GWh) will be generated by the Meridian power stations on the Waitaki scheme.

56 The System Operator can also bring forward access to contingent storage if operational risks mean there is an increased risk to security of supply ahead of using contingent storage. The System Operator has outlined its provided its discretion process in its public-facing Energy Security Outlook 101 and covered this off at its SO industry forum.

155. Currently if actual hydro storage crosses the Alert curve (either nationally or in the South Island), Alert status is triggered and Alert contingent storage is accessible for generation.[57] If this situation happens we would expect high wholesale market spot prices (prices rise as storage tracks towards the boundary of contingent storage). This incentivises available price-responsive market resources (fuels and assets) to generate or reduce consumption.[58] Figure 14 shows this correlation over the last five years between increasing spot prices and increasing thermal generation volumes as hydro storage reduces and approaches the Alert curve.[59]

156. Additional Emergency contingent storage in Lake Pūkaki becomes available when an OCC is triggered. An OCC is a Code-mandated regulatory mechanism that asks consumers of all types and sizes (including households, businesses and industrials) to voluntarily reduce their electricity consumption. An OCC is called if hydro storage is expected to remain below the Emergency curve for more than 7 days or unless otherwise agreed between the System Operator and Authority. The Emergency curve reflects a modelled 10% risk of running out of hydro storage (accounting for the Emergency CSRB floor as discussed in paragraph 66▪).

157. These current supply emergency protocols (including as reflected in the SOSFIP) utilise contingent storage as the fuel-of-last-resort: after all other fuels and resources have contributed in response to market price signals, before a public campaign asks consumers to voluntarily conserve power - and before it is necessary for rolling outages to cut supply to households and businesses. These regulatory protocols have been designed to buy time for it to rain before all useable hydro storage is used up.

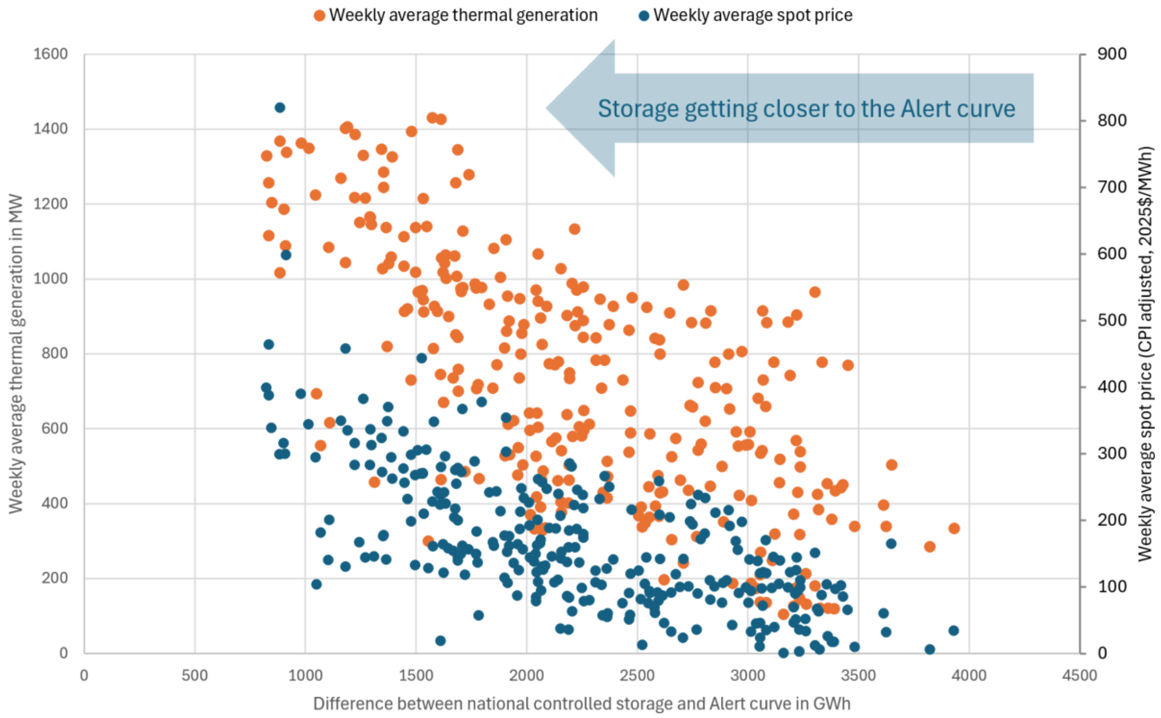

Figure 14 Increased thermal generation and spot prices as storage approaches the Alert curve

57 As discussed in paragraph 66, the Alert curve is the higher of a forecast 4% risk of future shortage and the Alert CSRB floor

58 This is consistent with the Authority's market design.

59 From January 2020

7.3 CSRB buffer default value

158. The Alert curve (also called the Alert CSRB) is the higher of a modelled 4% risk of running out of hydro storage and the Alert CSRB floor. The Emergency curve is the higher of a modelled 10% risk of running out of hydro storage and the Emergency CSRB floor.

159. The Alert (and Emergency) CSRB floor is the total contingent storage amount in all catchments at that status (and higher) plus a buffer to account for operational considerations that could prevent access to contingent storage. The SOSFIP currently sets the default buffer at 50 GWh. An illustration of this is shown in Figure 15 below.

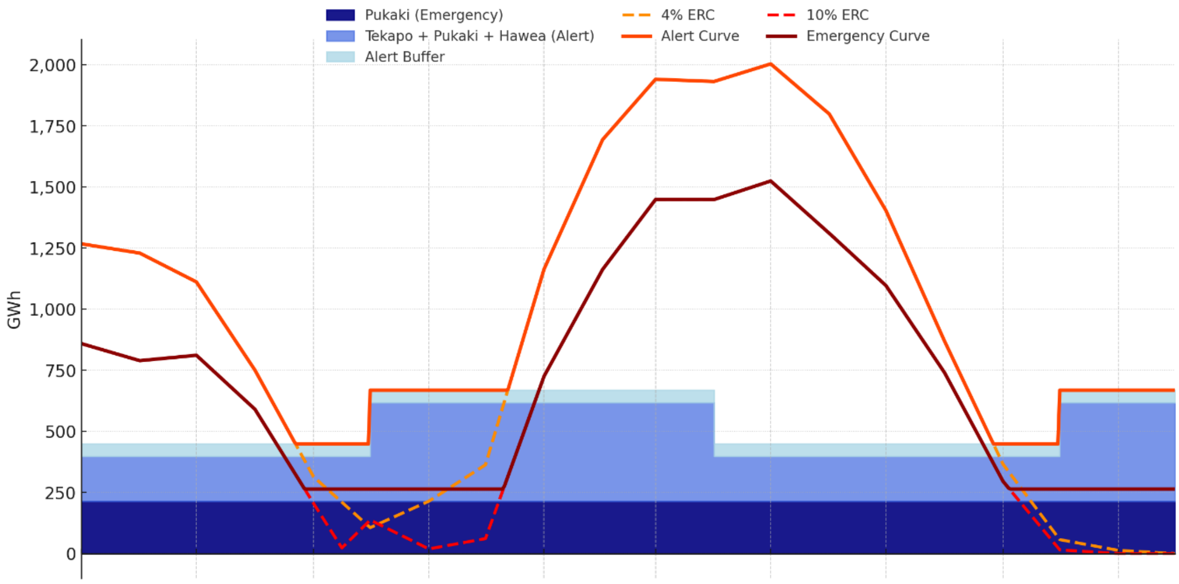

Figure 15 Illustration of components of the Alert and Emergency curve

160. The CSRB buffer, its default value, and the discretion for the System Operator to determine a different CSRB buffer, were introduced by SOSFIP amendments approved by the Authority following the 2018-19 review. The 2018-19 review also resulted in contingent storage being included within the ERCs. The System Operator's decision to propose the buffer mechanism was informed by stakeholder feedback to the consultation on its draft proposal. The consultation paper highlighted the risk of non-supply due to operational issues (caused by the security of supply situation) in advance of either contingent storage being accessed or an OCC being triggered.[60]

161. The effect of the default CSRB buffer is that the aggregate of all remaining controlled storage must be within 50 GWh of its minimum operating level before access to contingent hydro storage is triggered. If there are operational circumstances that may result in security of supply risks being realised ahead of contingent hydro storage being accessed, the SOSFIP permits the System Operator to use its discretion to increase the CSRB buffer. If the System Operator uses the CSRB buffer discretion, access to contingent storage will be brought forward in all the lakes with contingent storage at the same time. The System Operator does not have discretion to

60 See SOSFIP Decision March2019 final22Mar.pdf

take more targeted action (perhaps directed at a single storage lake), or to take a different action not already set out in the SOSFIP.

162. Given the intent of contingent storage to be the fuel of last resort, and to provide transparency in how this can be accessed there is a tension in setting the default CSRB buffer value. If set too large, it will enable unfettered access to contingent hydro storage that would not be consistent with the expectations set in the WAP and resource consents. Enabling contingent storage to be utilised ahead of other market resources can reduce incentives on retaining other non-hydro back-up resources (such as coal, gas or long-term demand response) with downstream and potentially long-term negative impacts on security of supply.[61] On the other hand, if set too small it will always require System Operator discretion to activate use of contingent hydro storage, potentially increasing market uncertainty if the System Operator's process for adjusting the buffer is not well understood.[62]

163. In August 2024, in response to rapidly declining hydro storage levels that had the potential to result in an inability to meet peak demand during any late winter / early spring cold snaps, we applied the CSRB buffer discretion for the first time. Informed by consultation with stakeholders, this decision brought forward the ability for generators to access contingent storage. In parallel, the market had responded by securing additional gas supplies for generation through agreement with Methanex. Spring inflows eventually arrived with the result that contingent storage was not used.

7.3.1 Contact proposed a higher Alert CSRB buffer for access to contingent hydro storage

164. In response to the Issues Paper Contact Energy proposed that the Alert CSRB buffer should be set so that contingent hydro storage is accessible when controlled storage is below 1,700-2,000 GWh.[63]

165. The current Alert curve trigger mechanism was put in place in 2019 and to date, controlled storage has not dropped below the Alert curve. Figure 16 below shows the CSRB for 2025 (the Alert status curve) with the current default buffer (50GWh) and the Contact-proposed CSRB, relative to historical controlled storage trajectories nationally and in the South Island over the past 30 years. Years that drop below the 2,000 GWh and 1,700 GWh trigger levels proposed by Contact are highlighted. Assuming the operation of controlled storage is not otherwise impacted by a materially larger buffer, the table below shows how often hydro storage would have crossed these trigger levels.

	Contact-proposed trigger	
	2000 GWh	**1700 GWh**
New Zealand	11 of 30 years (37%)	4 of 30 years (13%)
South Island	17 of 30 years (57%)	11 of 30 years (37%)

61 See Meridian seeks unfettered lake access; Genesis would reduce coal | Energy News
62 The System Operator has published its buffer discretion process in its ESO101 available here: Energy Security Outlook 101
63 See Contact Energy - SOSFIP Review - Issues Paper Questions - March 2025.pdf

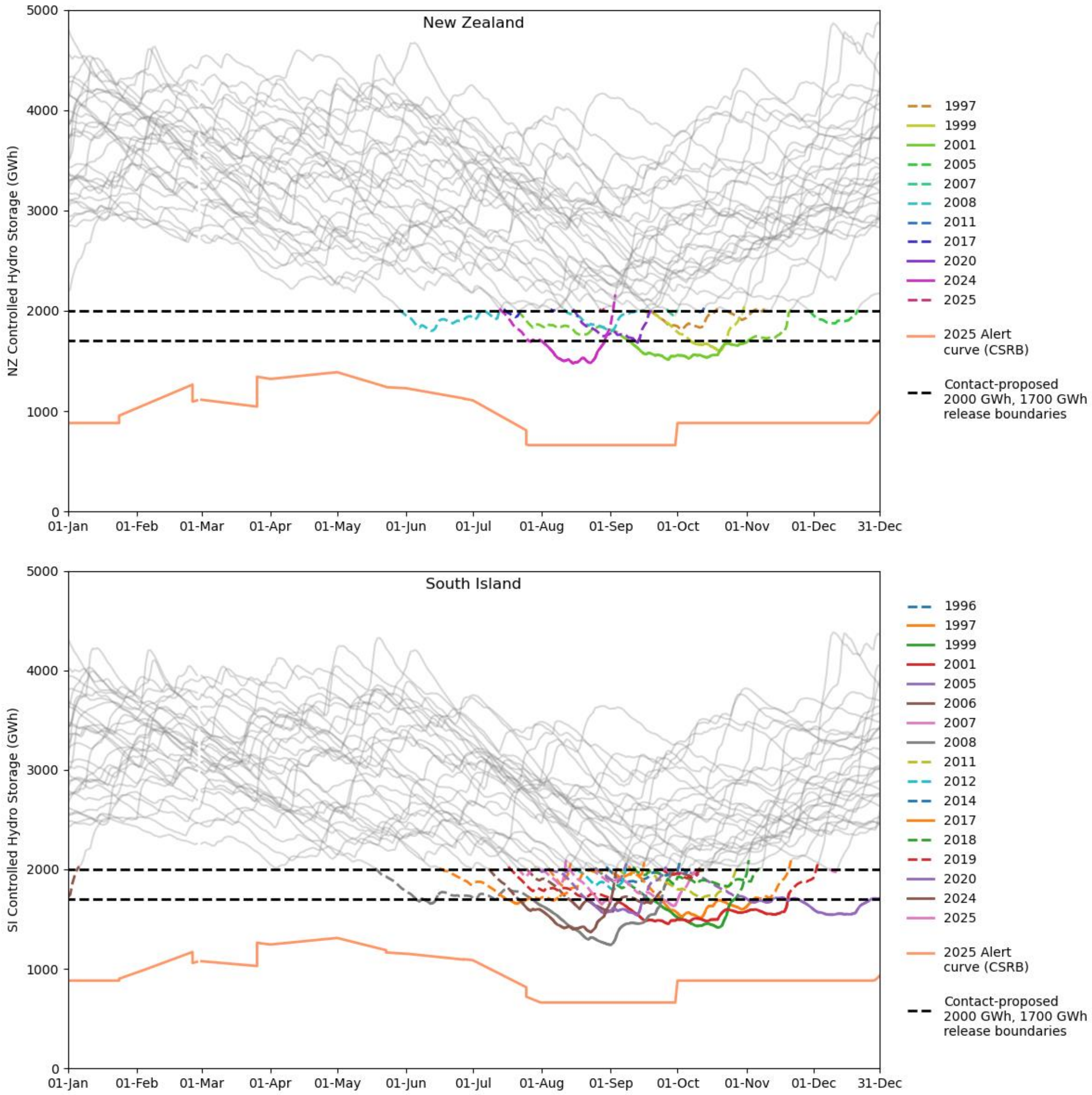

Figure 16 Contact Energy proposed increased trigger for access to contingent storage versus historical storage

166. We have also considered the effect had the Contact-proposed trigger been used during Winter 2025. Figure 17 below is the July update of the ERCs reproduced using the Contact-proposed buffer shown by the horizontal shaded band. This shows that the contingent storage trigger range is much higher than the current Alert curve (up to 1338 GWh higher than the current Alert curve). Had this been the situation the System Operator would have been required to declare Alert status for the South Island in mid-August despite there being no scarcity of fuels (including stored water and thermal fuels) available to the power system, and no reasonable expectation that an electricity supply emergency situation was emerging.

167. While this provides early access and high certainty to Contact, Meridian and Genesis in accessing contingent storage in Lakes Hāwea, Pūkaki and Tekapo, it enables this access ahead of a security of supply emergency and other market resources. Enabling access to contingent hydro storage too early can have security risks, as discussed in the next section.

168. For these reasons, we do not support the trigger level proposed by Contact be used as the default trigger for access to contingent hydro storage.

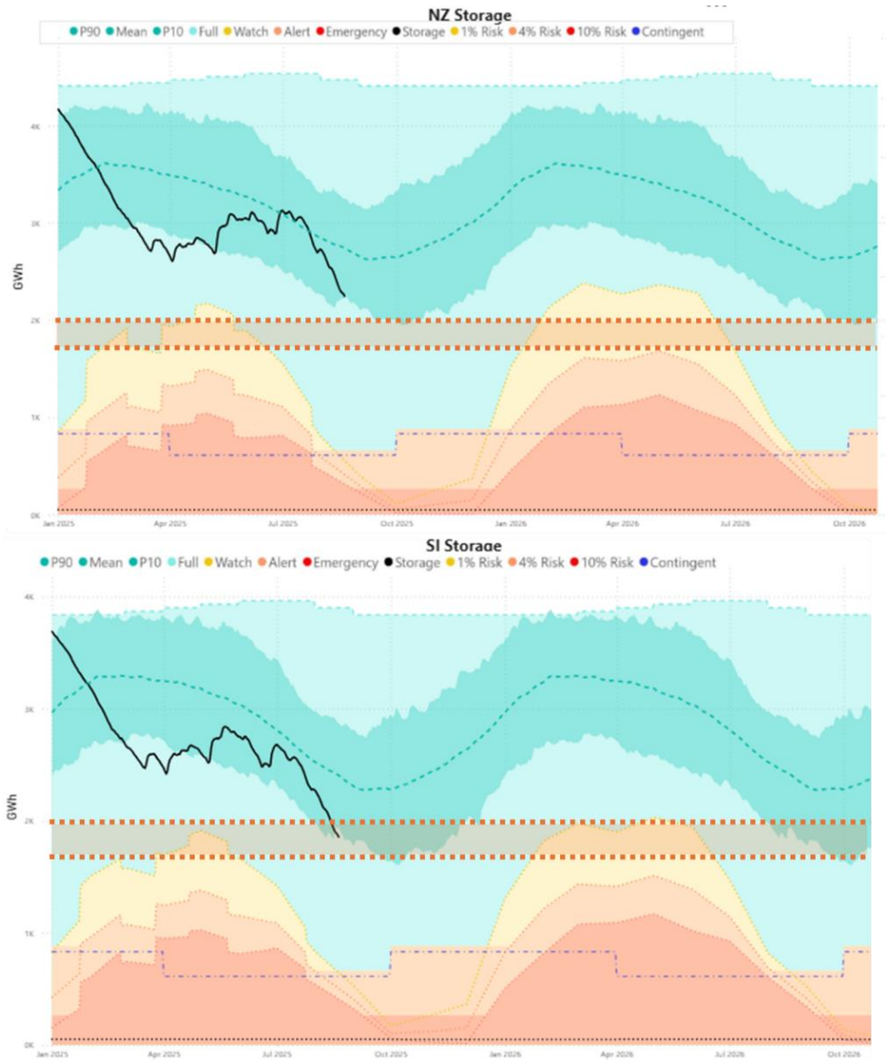

Figure 17 Contact Energy proposed increase trigger for access to contingent storage

7.3.2 Meridian requested higher Alert and Emergency CSRB buffers

169. Meridian has requested the contingent storage buffer for both the Alert and Emergency curves be raised.[64] Meridian considers the current default 50 GWh buffer fails to take account of operational constraints in the low operating ranges of Lakes Manapouri and Te Anau (that restrict access to 150 GWh of stored water) and the 'shadow constraint' caused by the increase in the minimum permitted lake level in Lake Tekapo between 1 October and 31 March (220 GWh) each year. Meridian's view was that Genesis appears reluctant to reduce Lake Tekapo below 220 GWh of remaining storage. Meridian would prefer its proposed amendment to the buffers be adopted permanently. However, it also supported an alternative of making the changes on a temporary basis out to 2027.

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64 See Meridian SOSFIP Review - Issues Paper Submission - March 2025.pdf

170. Meridian provided feedback that the "effect of these constraints is to bar access to contingent storage in a manner that was not seemingly contemplated when drafting the current SOSFIP and specifying the current buffers." As a result, Meridian suggests it is "not practically possible in most scenarios for the Alert CSRB to be triggered." Meridian proposed that the Alert and Emergency buffers both be increased by the amount of Manapouri/Te Anau and Tekapo stored water that it considers cannot reliably be accessed ahead of a need to access contingent storage.

171. Meridian had previously proposed the same adjustments to the Alert and Emergency CSRB buffers in its response[65] to our August 2024 consultation that informed our decision to lift them in spring 2024. Our decision paper at the time provided our consideration of Meridian's feedback.[66]

172. Then later in 2024 Meridian wrote to us to requesting a permanent change to the Alert and Emergency CSRB buffer and there should be an urgent review of the SOSFIP prior to Winter 2025.[67] Our response noted that the proposed amendment to the Emergency CSRB buffer would bring forward access to Emergency contingent storage in Pūkaki, and bring forward the trigger point for an OCC.[68]

173. Figure 18 below shows the proposed changes by Meridian to the Alert curve. The proposed Alert curve shown by the orange dashed line, and the proposed Emergency curve by the red dashed line.

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65 Meridian submission - 2024 Adjustment to Alert Contingent Storage Release Boundary.pdf

66 ERC_buffer_decision_22Aug2024.pdf

67 Letter to Transpower on Contingent Storage_Public.pdf

68 241220 TP-SO letter to Meridian - enabling access to contingent storage - December 2024.pdf

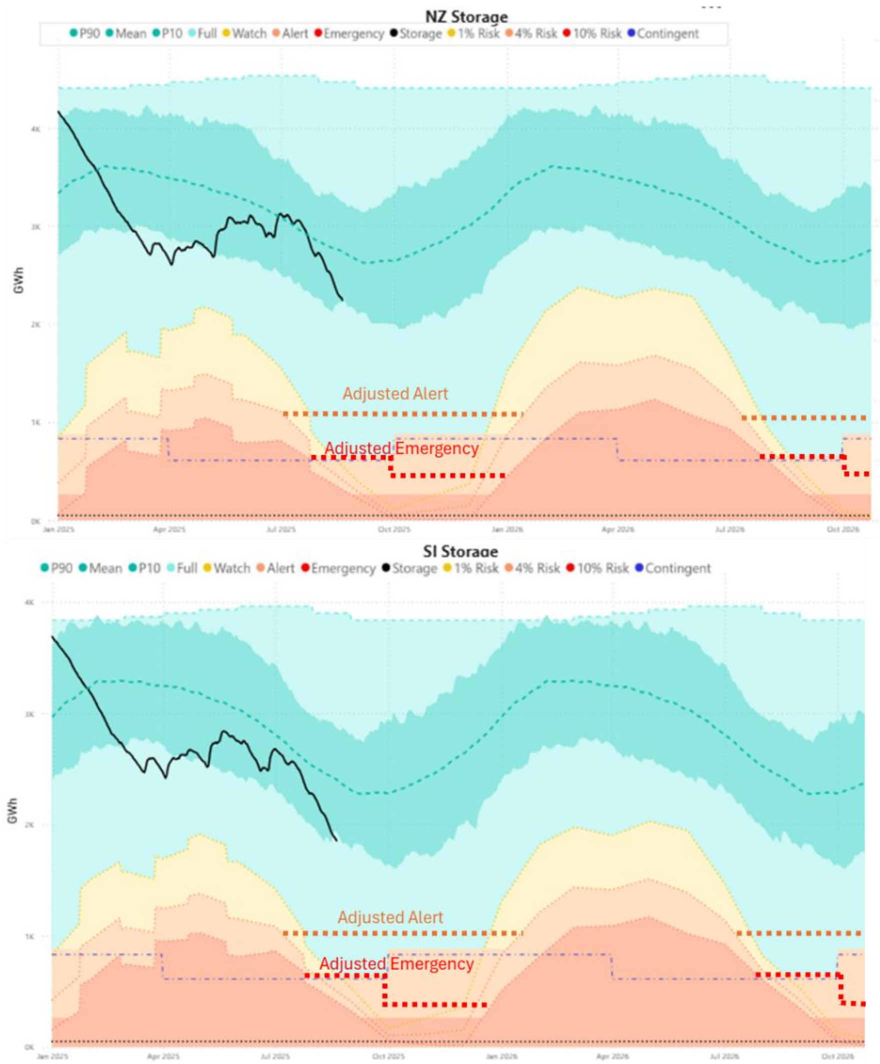


Figure 18 Meridian Energy proposed increase trigger for access to contingent storage

174. We discuss our consideration of the issues raised by Meridian below.

7.3.3 Waiau low range operating constraints

175. Given the buffer is to allow for operational circumstances that can prevent access to contingent storage we assessed the buffer value and operational constraints that could prevent triggering access to contingent hydro storage. We looked at the Waiau (Lakes Manapouri and Te Anau) and Lake Tekapo operational restrictions that prevent these lakes being drawn down to their minimum storage levels. As a result, these restrictions could inflate the aggregate hydro storage levels and therefore prevent the trigger activation restricting access to contingent hydro storage.

176. Lakes Manapouri and Te Anau are the major hydro reservoirs in the Waiau catchment. The operational restrictions for these lakes, including the different low operating ranges, the maximum time that can be operated within each band, and drawdown rates, are specified in the gazetted Operating Guidelines for Levels of Lakes Manapouri and Te Anau. Meridian's feedback to us was on the basis of the guidelines that were current at the time (the old restrictions). Subsequently, changes to these guidelines were agreed between Meridian and the Guardians

of Lake Manapouri and recommended to the Minister for Energy. The Minister approved the recommended amendments, which were gazetted in May 2025, after we received Meridian's feedback. [69] The effect of the new guidelines was to increase operational flexibility (so reduce operational restrictions) when storage drops into the low operating range.

177. A summary of the key differences between the between the old and new restrictions on low range Waiau operation are shown in the figure below. The main difference is materially greater operational flexibility in the 151 GWh to 103 GWh range: the number of days the lakes can be operated in this range is now unlimited, and the allowable drawdown rate has been increased from 7.4 GWh to 12.2 GWh.[70]

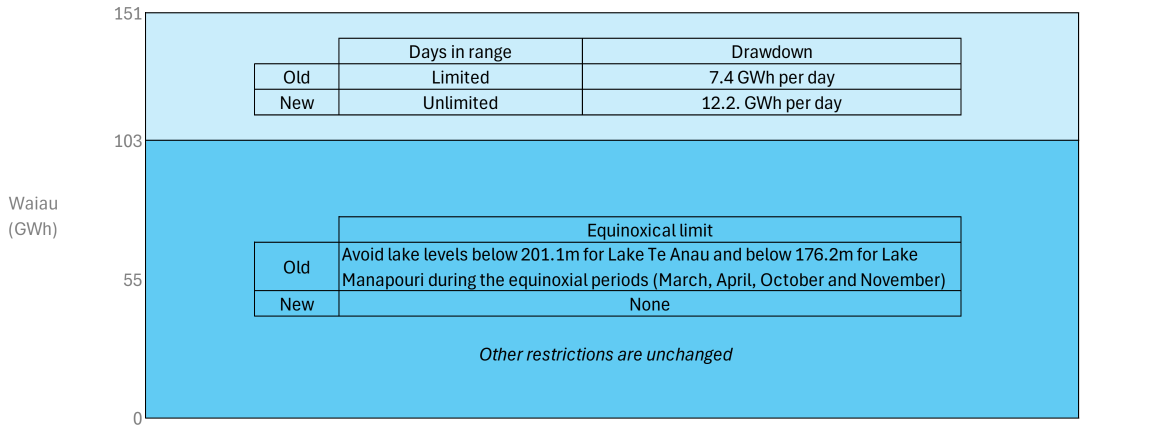


Figure 19: Summary of old and updated restrictions on Waiau low range operation

178. We have reviewed historical operating practices across the last 46 years. Figure 20 shows Waiau storage regularly dropping into the original low range (below 150 GWh as shown by the orange line) and also reducing below 103 GWh (red line) in ~18 of the last 46 years.

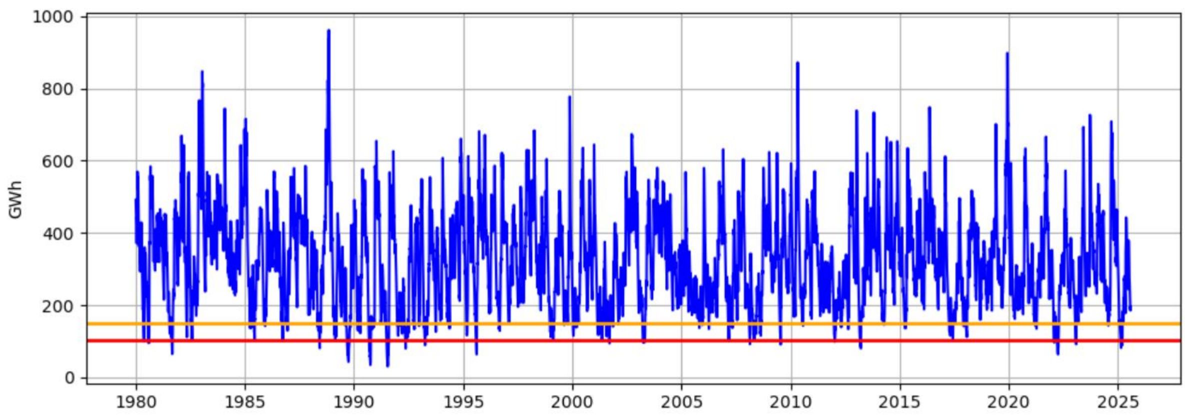


Figure 20: The reduction in the start of low range operation in comparison to Waiau storage since 1980

69 The details of the operating guidelines are here (Operating Guidelines for Levels of Lakes Manapouri and Te Anau - 2025-go2889- New Zealand Gazette)

70 To provide some context on the flexibility of the increased drawdown, when the Waiau is below mean storage, for approximately 95% of the time (from Jan-1980 to July-2025), its drawdown was less than 11 GWh per day.

179. Figure 21 summarises the historic low range operations in terms of outcomes for remaining stored water. When the Waiau was operating below 103 GWh, the minimum it reached was ~30 GWh and has been below ~85 GWh for about 50 percent of the time spent in the low range.

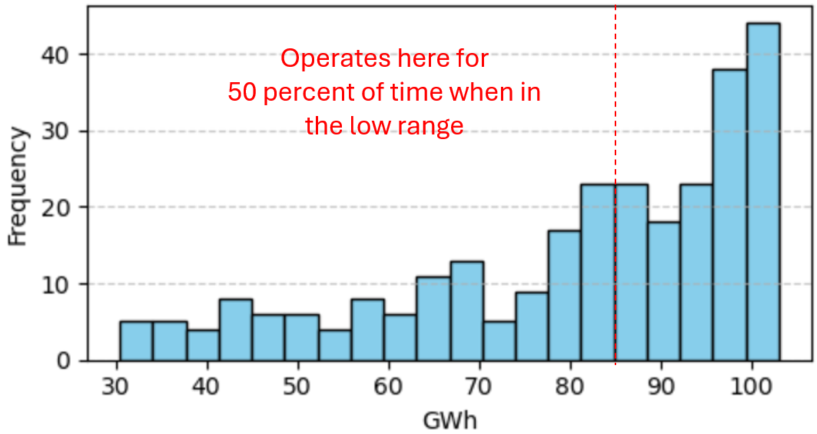


Figure 21: Histogram of Waiau low range storage operation from 1980

180. This analysis shows that while there are operational restrictions, the Waiau is regularly operated within the low operating range. The new Manapouri and Te Anau operating guidelines have, for the next 12 years, reduced the low range operating restrictions when the Waiau storage is between 150 GWh and 103 GWh. The previous restrictions still largely apply below ~103 GWh. On the basis of both these factors we consider a contribution to the CSRB buffer of 150 GWh to account for the low operating range constraints in the Waiau is not justifiable.

181. Further, the Waiau storage has historically been operated in the lowest operational range (103 to 0 GWh). Based on our records, the lowest it has been drawn to since 1980 is ~30 GWh. This sets a potential lower bound on the buffer for the Waiau storage. Therefore, we think a plausible buffer to account for Waiau low range operational restrictions is between 30 and 103 GWh.

182. When operating below 103 GWh, the Waiau storage is for the most part operating in the upper end of the low range. However, Meridian has for ~50% of the time operated the Waiau lower than 85 GWh. Hence, we consider a 90 GWh buffer to account for the low range Waiau constraints balances operational requirements with prudent storage management incentives.[71]

7.3.4 Tekapo operational constraint

183. The Tekapo operational constraint is related to a resource consent condition which includes a 220 GWh step up in the minimum level of Lake Tekapo on 1-October each year. As covered in the Issues Paper, this creates a breach risk for Genesis should it use the lower range water from April to September (which it can access without an Alert) and then breach the 1 October limit if (say) spring inflows arrive late. The figure below (from the Issues Paper) shows the level of Lake Tekapo back to 1992. While on three occasions (during winter) the lake has dipped into storage that is contingent during summer, the records do suggest operating practice is to avoid using the full range of water that is accessible during winter (between 1-April and 30-September).

71 See Appendix 2 for some examples of when the storage was operated below 103 GWh and when this dropped below 90 GWh.

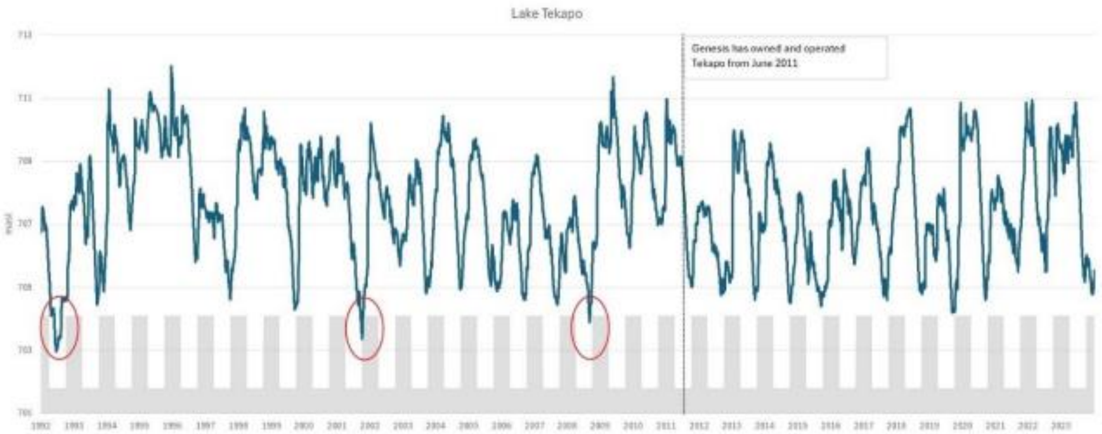


Figure 22: Lake Tekapo storage compared to minimum operating level

184. Our decision to raise the CSRB buffer (for a limited time) was in part due to this shadow constraint and uncertainty arising from concerns that Genesis would not use the full operating range if the winter 2024 dry period had extended into September. We considered this time-bound adjustment was an appropriate response to a time-related compliance risk at Lake Tekapo that led to a potential time-bound energy constraint for the power system. It did however also bring forward access to contingent storage in all of Lakes Pūkaki, Tekapo and Hāwea where access in all cases is linked to the Alert curve.

185. The best permanent solution would be for the Genesis consent conditions to be amended to increase the usability of the water in Lake Tekapo from 01-April to 30-September. The renewal of Genesis's resource consents, which is currently underway, provides an opportunity to address this issue.

186. Based on Genesis' current consents, we have considered a conservative operating strategy for use of storage accessible in Tekapo from 1-April to 30-September, with expected generation from the scheme and a pessimistic view for inflows to return storage back up to the minimum required level by 1-October – as illustrated in Figure 23. We have used this analysis to consider whether a permanent change in the default buffer could be needed to account for Tekapo storage that has a high likelihood of not being used during winter.

187. For the period 1 April to 30 September we have assumed what we consider to be a conservative Tekapo storage usage strategy:

- Genesis reduces Lake Tekapo to "X" GWh, where "X" is < 220 GWh, is the amount of storage that can be restored by 1 October, and reduces as winter progresses towards spring.
- Tekapo receives low inflows (P5 inflows) until 1 October, and
- Genesis generates at expected (historically observed) output given during low inflow periods (P50) until 1 October.

188. A non-zero "X" indicates a potential need for a buffer allowance to account for storage that might not be accessed in order to avoid breaching the higher consented minimum operating level on by 1-October.

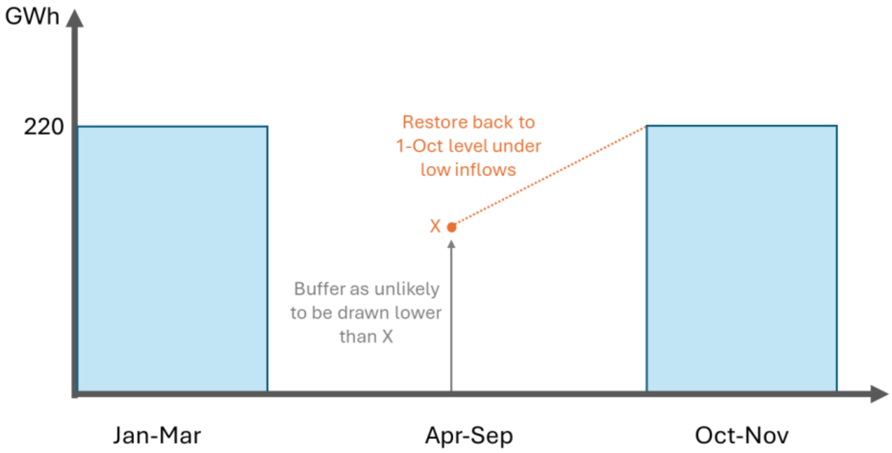


Figure 23: Lake Tekapo "worst-case" usage for buffer calculation

189. We used this approach and historical Tekapo inflows (since 1931) and Tekapo generation (since 2012[72]) to estimate 'X' values for our conservative Tekapo storage usage strategy.

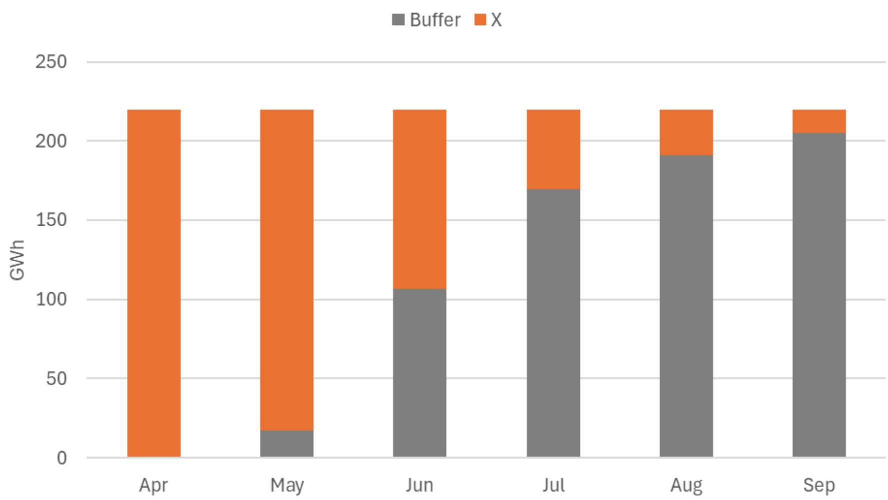


Figure 24: Lake Tekapo buffer calculation by month

190. Based on this analysis an allowance in the default buffer to account for the Tekapo shadow constraint would be:

Apr	May	Jun	Jul	Aug	Sep
0	20	110	170	190	210

191. If there are changes to the Tekapo contingent storage resource consent conditions and/or changes to the Waiau low range operating limits, the calculated buffer would also need to be updated to make sure it is still fit for purpose.

72 We used data from 2012 because Genesis took ownership of the Tekapo hydro scheme from June 2011. Prior to this it was part of Meridian's generation portfolio.

7.3.5 A higher default buffer, profiled across the year could better account for operational limitations

192. The net effect of these adjustments results in a buffer profile across the year as follows:

	Base	Waiau	Tekapo	Total
Jan	50	90	0	140
Feb	50	90	0	140
Mar	50	90	0	140
Apr	50	90	0	140
May	50	90	20	160
Jun	50	90	110	250
Jul	50	90	170	310
Aug	50	90	190	330
Sep	50	90	210	350
Oct	50	90	0	140
Nov	50	90	0	140
Dec	50	90	0	140

Table 1: Adjusted Alert CSRB buffer

193. We consider the key benefits and drawbacks of this buffer profile are:

Table 2: Benefits and drawbacks of adjusted CSRB buffer	
Benefits	The proposed default buffer values account for the recent changes in low range operation in the Waiau and potential operation of Lake Tekapo in its normal range between April and September (reducing uncertainty for participants due to the perceived shadow constraint).
	These changes better reflect the potential operational restrictions on storage that could prevent triggering of contingent storage when needed.
	By incorporating these effects into the buffer, there is increased certainty for market participants and less need for the System Operator to apply its discretion.
Drawback	The proposed higher buffers would increase the potential for contingent storage to be accessed for generation while other market resources are yet to be fully utilised, relative to the status quo. We have tried to minimise this effect by considering the operational constraints observed in the market that could restrict hydro usage and thus block the trigger for contingent storage from activating.

194. In our view, while the operational matters Meridian raises have potential merit with respect to the Alert curve, the same rationale does not translate to the Emergency curve. This is because the Alert status would have been triggered and in effect before an OCC is triggered meaning access to Tekapo contingent storage would be available.

195. Secondly, with the Waiau constrained low range operation accounted for in the Alert buffer, low range storage could largely be available even under Alert status. We consider Waiau low range storage should be used before the public is requested to voluntarily manage load through an OCC.

196. Furthermore, permanent changes that increase the likelihood of an OCC (e.g. by permanently raising the Emergency buffer) should be considered in conjunction with a review of the CCS to

make sure these are providing sufficient incentives to prudently manage hydro storage (including contingent hydro storage).

197. Hence, we are not proposing any change to the Emergency buffer as part of this SOSFIP Review. We propose a review of CCS is needed to ensure the incentives (and risks) of using contingent storage are adequately considered. The Emergency buffer is linked to this and should be considered together with the CCS review.

198. While we could make the change to the Alert CSRB buffer temporarily using the ability we have in clause 6.1A(c) of the current SOSFIP to determine and publish a buffer different to the default, our strong preference is that any change is instead made permanently by amending the SOSFIP, after consultation. In our view the permanent approach is necessary to improve certainty and transparency about the power system conditions under which contingent storage could be accessed by generators.

System Operator proposal

199. We propose updating the buffer for the Alert curve to the proposed values in Table 1 above, to better account for the changes in the operating restrictions at the different hydro catchments. We do not propose any changes to the buffer applied to the Emergency curve.

200. Our proposed changes to the SOSFIP are in clause 6.1A(c) of the SOSFIP in Appendix 1.

Question 12

Do you agree with the proposal to update the Alert CSRB buffer for the access to contingent hydro storage? If not, please provide reasons for your answers.

7.4 CSRB buffer discretion

201. The SOSFIP includes a specific discretion to allow the System Operator to determine a different CSRB buffer and make it publicly available. This discretion was included in the current SOSFIP to allow flexibility for the System Operator to bring forward access to contingent storage if the operational circumstances make doing so necessary to mitigate an immediate risk to security of supply.

202. The System Operator exercised its CSRB buffer discretion for the first time in 2024, as summarised in Box 3. In 2024 the System Operator consulted stakeholders before deciding to use its CSRB buffer discretion. Consultation was undertaken because there was time to do so before the physical risk would be realised (including allowing time for generators to complete the necessary operational preparations), and the decision had potentially material impacts for all market participants and the communities local to hydro catchments with contingent storage.

Box 3: In 2024 the System Operator used its CSRB buffer discretion for the first time

In August 2024 the System Operator decided to use an Alert curve CSRB buffer in circumstances where:

- The Alert curve was not close to being hit because there was enough fuel remaining across the system to supply generators and meet forecast demand for energy. A factor was the timing. Being late winter the forecast assumed the historically typical spring pick-up in inflows was expected to arrive 'soon' along with the warmer temperatures that result in less demand for electricity.
- The Waitaki scheme, New Zealand's largest storage scheme had sufficient storage in aggregate, but some of that was held upstream in Lake Tekapo, which we understand was to meet resource consent conditions. Lake Pūkaki, downstream of Tekapo, was low. Lake Hāwea was also low.
- While aggregate storage was above the Alert curve, the unequal drawdown of hydro storage meant there was a risk that both Pūkaki and Hāwea could reach their minimum normal operating range without access to contingent hydro storage.
- Without access to contingent storage either or both the Waitaki and Clutha schemes could have been required by resource consents to reduce generation to match the prevailing low hydro inflows. This would have severely constrained the schemes' ability to flex up to meet peak demand especially during any cold snap that may (and often does) occur in spring.
- Available coal and gas supplies were being used, there was not enough time available to source more coal, and securing more gas required a demand response contract to shut down Methanex's operations.

The System Operator's analysis concluded there was an immediate security of supply risk, limited opportunity for a market response, and removing barriers to access contingent storage could help alleviate these risks.

203. In keeping with the intended use of contingent hydro storage as a fuel of last resort, the System Operator's current criteria against which any decision to apply the CSRB buffer discretion is assessed are:

- there is an immediate risk to security of supply, and
- there is limited time for a market response to mitigate the risk, and
- bringing forward access to contingent storage can mitigate the risk.

204. To improve certainty on our process for updating the CSRB buffer, we provided further details to the industry in 2025 via our System Operator industry forum and updated Energy Security Outlook 101 on our approach to ongoing monitoring of risks and assessing the need to apply the CSRB buffer discretion. These are outlined in Box 4.

Box 4: Ongoing monitoring for a need to apply the CSRB buffer discretion

- Monitor aggregate hydro storage: If aggregate hydro storage is below historic mean for the time of year, we assess, and update at least weekly, the estimated 'time to' for the worst-case SST to reach the current national and/or South Island Alert risk curve. If the 'time to' is less than 3 months, then we initiate the CSRB buffer discretion process on the basis there is an emerging energy risk.
- Monitor individual lake risks: If aggregate hydro storage is below historic mean for the time of year, each week we also assess the 'time to' reach the boundary of contingent storage in each lake with contingent storage. If a lake could (on the basis of its contribution to the worst-case SST) reach its contingent storage boundary before aggregate storage would cross the Alert curve, we apply our CSRB buffer discretion process to assess whether it would create a capacity risk.
- Engage with generators to understand operational limitations: To ensure we understand the operational limitations of each generation scheme as a low inflow sequence evolves, we engage with the generators to ensure the information we hold is up-to-date. While we proactively ask for any new information to inform each update of the ERCs, we also ask that generators keep us informed should circumstances change at any time.

205. Figure 25 provides an overview of the steps and timelines for the CSRB buffer discretion process for Winter 2025. Box 5 explains the steps in more detail. This is the process we will use to for energy and capacity security of supply risks that are emerging over time. The process balances the need for greater certainty around the availability of contingent storage with the need to adapt the approach to changing conditions.

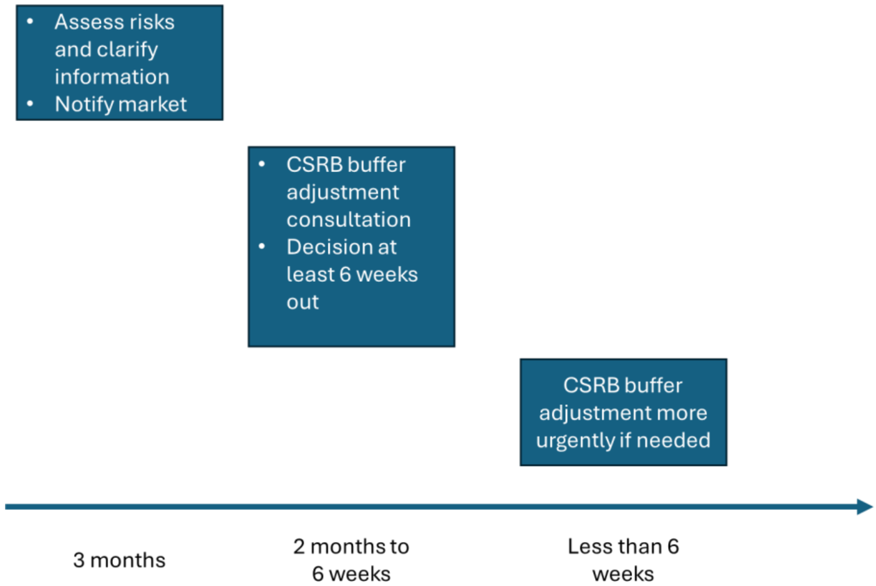


Figure 25: Overview of the CSRB buffer discretion process for Winter 2025

Box 5: CSRB buffer discretion process to increase the buffer

STEP 1: ASSESS ENERGY RISK AND CAPACITY RISK (3 months ahead)

A. <u>Assess whether there is an immediate energy risk:</u> An energy risk is realised if the power system is unable to fully meet consumer energy demands (i.e. there is insufficient fuel in the system). We consider there is an immediate energy risk emerging if the worst-case SST indicates there is the potential for unserved energy within the next 3 months.

B. <u>Assess whether there is an immediate capacity risk:</u> We also consider the ability of the power system to meet peak demand with the impacted generation scheme(s) peaking capability restricted due to minimum flow requirements under resource consents (capacity risk). A capacity risk is realised if the power system is unable to fully meet consumer demands for electricity at a particular time (typically during a morning or evening peak during cold, still weather conditions). If one or more individual catchment is forecast to cross its contingent storage boundary within the next 3 months, and the operational implications for the affected generation scheme(s) would put at risk the system's capacity to supply peak demand in a cold snap, we will conclude there is an immediate capacity risk emerging.

C. <u>Trigger the process to consult on a draft CSRB buffer discretion decision:</u> If there is an energy or capacity risk emerging within the next 3 months we trigger the next step in the process, which is to consult on the use of the CSRB buffer discretion. During this process we:

- Check our assumptions and information are correct: Information on fuel, capacity and operational issues is confirmed with participants. We also seek information on the potential for market response options that may yet be available to participants.
- Inform industry and other stakeholders: We inform industry and other stakeholders (including via the System Operator's industry forum) of the potential risks and need for a heightened response from the market.
- Complete analysis and prepare a draft decision for consultation: In parallel with checking our assumptions and seeking information from participants, we complete our analysis of the security of supply risk, and the potential for use of the CSRB buffer discretion to mitigate it. We make a draft decision about the quantum and timing for different buffer(s) to be in effect.

STEP 2: COMPLETE URGENT CONSULTATION ON RAISING CSRB BUFFER(S) (2 months ahead minimum)

<u>Consult on the draft CSRB buffer decision:</u> Consultation will run for 1 week. Following consideration of feedback we will review our decision, make a final assessment against our criteria for applying the discretion, and prepare a final decision paper setting out our response to feedback and the rationale for our final decision.

STEP 3: COMMUNICATE DECISION (6 weeks ahead minimum)

<u>Communicate the final CSRB buffer decision:</u> Our final decision on whether to use the CSRB discretion is published. If we have decided to use the discretion, our decision will set out the quantum, and timing for the different CSRB buffer(s) to be in effect.

206. Capacity risks to security of supply can also develop more quickly in response to a fast-moving event such as material asset failure(s). Box 6 sets out the approach we will apply should a scenario of this type require a much quicker decision to be made.

Box 6: CSRB buffer discretion process – fast-moving event

COMMUNICATE DECISION (any time)

Application of discretion with no consultation: Capacity risks and potentially some energy risks can also emerge much more quickly due to unplanned generation outages or fuel supply interruptions. Our ongoing focus on monitoring levels and inflows in each controlled hydro storage lake individually is part of making sure early warning signs of a developing capacity risk are picked up in time for participants to mitigate it through a market response. However, if at any time a security of supply risk emerges rapidly and there is not enough time to complete the full process we will move more quickly. This would result in an immediate decision that the criteria have been met.

207. We consider that maintaining discretion is important to ensure access to contingent hydro storage can be triggered if security of supply risks evolve differently. Following our consultation earlier in 2025, there was widespread support for us to maintain our discretion in adjusting the CSRB buffer.

208. To ensure there is certainty in our process when adjusting the CSRB buffer, we propose to add a SOSFIP requirement to publish this process.

System Operator proposal

209. We propose to:

- retain in the SOSFIP the ability to decide on a different CSRB buffer if the operational circumstances require it at the time.
- Add to the SOSFIP a requirement that we use our published CSRB buffer discretion process when deciding whether to determine a different buffer.

210. Our proposed changes to the SOSFIP are in clauses 2.1 (definition of "CSRB buffer discretion process") and 6.1BB of the SOSFIP in Appendix 1.

Question 13

Do you agree with the proposal for the System Operator to retain the CSRB buffer discretion process? If not, please provide reasons for your answers.

8 Regulatory statement for the proposed SOSFIP amendment

8.1 Objectives of the proposed SOSFIP amendment

211. The objective of the SOSFIP amendment we propose is to ensure the SOSFIP remains fit for purpose in its intended role, which is to outline the approach that the System Operator takes in providing information and forecasting in relation to security of supply. Security of supply in the context of the SOSFIP is the New Zealand power system's current and future ability to meet electricity demand at a national and South Island level.

212. The proposal evolves the requirements of the SOSFIP to improve certainty and so better support market participants to ensure security of supply into the future by:
    - showing physical versus contracted capability in the ERCs and SSTs
    - ensuring Watch status always precedes Alert status
    - avoiding the potential to flip-flop in and out of Alert status
    - expand the set of scenarios the System Operator must consider beyond thermal fuel supply disruptions
    - permanently adopting a seasonally profiled default CSRB buffer that better reflects hydro storage catchments' operational limitations
    - requiring the process the System Operator uses to temporarily decide on a CSRB buffer different to the default to be published and used.

Question 14

Do you agree with the objectives of the proposed SOSFIP amendment?

8.2 The proposed SOSFIP amendment

213. The drafting of the proposed SOSFIP amendment is shown in the track-change version of the SOSFIP included in Appendix 1 of this consultation paper.

8.3 The proposed SOSFIP amendment's benefits are expected to outweigh the costs

214. Assessing the effect of the proposed SOSFIP amendment is complex and not easily quantifiable. We consider that a full quantitative analysis of the costs and benefits of the proposal is not practical in this case.

215. The cost for the System Operator to implement the proposed SOSFIP amendment is expected to be immaterial and able to be absorbed within the System Operator's fixed fee funding already agreed with the Authority until 30 June 2028.

216. We consider the proposed SOSFIP amendment is targeted at addressing matters that participants have told us contribute to uncertainty in relation to security of supply risks, including the circumstances in which contingent storage can be accessed. We consider that our proposed SOSFIP amendment will provide benefits of certainty and clarity around the application of the SOSFIP which will support participants to better determine what to do and when to do it when supply is tightening.

217. Our assessment is that by providing additional clarity and reducing uncertainty, the SOSFIP will better support its purpose and better meet the Authority's main statutory objective under section 15 of the Electricity Industry Act.

Question 15

Do you agree it is appropriate to rely on qualitative evaluation of the costs and benefits of the proposed SOSFIP amendment? If not, what information, evidence etc can you provide and/or what methods would you recommend to quantify the costs and benefits?

Question 16

Do you agree the benefits of the proposed amendment to the SOSFIP can reasonably be expected to outweigh its costs

8.4 The proposed SOSFIP amendment is preferred to other options

218. In developing the proposed SOSFIP amendment, we compared each proposed change against the current SOSFIP (the status quo option) and any other variants and options we identified.

219. For example, we considered different options for ensuring Watch status is always triggered before Alert and evaluated the benefits and drawbacks of each.

220. The proposed SOSFIP amendment is based on our experience and expertise in the role of System Operator. We would welcome feedback on any other potential amendments we should consider.

8.5 The proposed SOSFIP amendment complies with the Act s32(1)

221. 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. The additional objective only applies, however, to the Authority's activities in relation to the dealings between participants and domestic and small business consumers, under section 32(3).

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

223. We consider that the proposed SOSFIP amendment complies with section 32(1) of the Act because it is desirable to promote, for the long-term benefit of consumers:

- **reliable supply by, and the efficient operation of, the electricity industry**: As noted above, we consider that the proposed SOSFIP amendment is targeted at addressing matters that participants have told us contribute to uncertainty in relation to security of supply risks, including the circumstances in which contingent storage can be accessed. We consider that our proposed SOSFIP amendment will provide benefits of certainty and clarity around the application of the SOSFIP which will support participants to better determine what to do and when to do it when supply is tightening.

Question 17

Do you agree that the proposed amendment complies with section 32(1) of the Act?

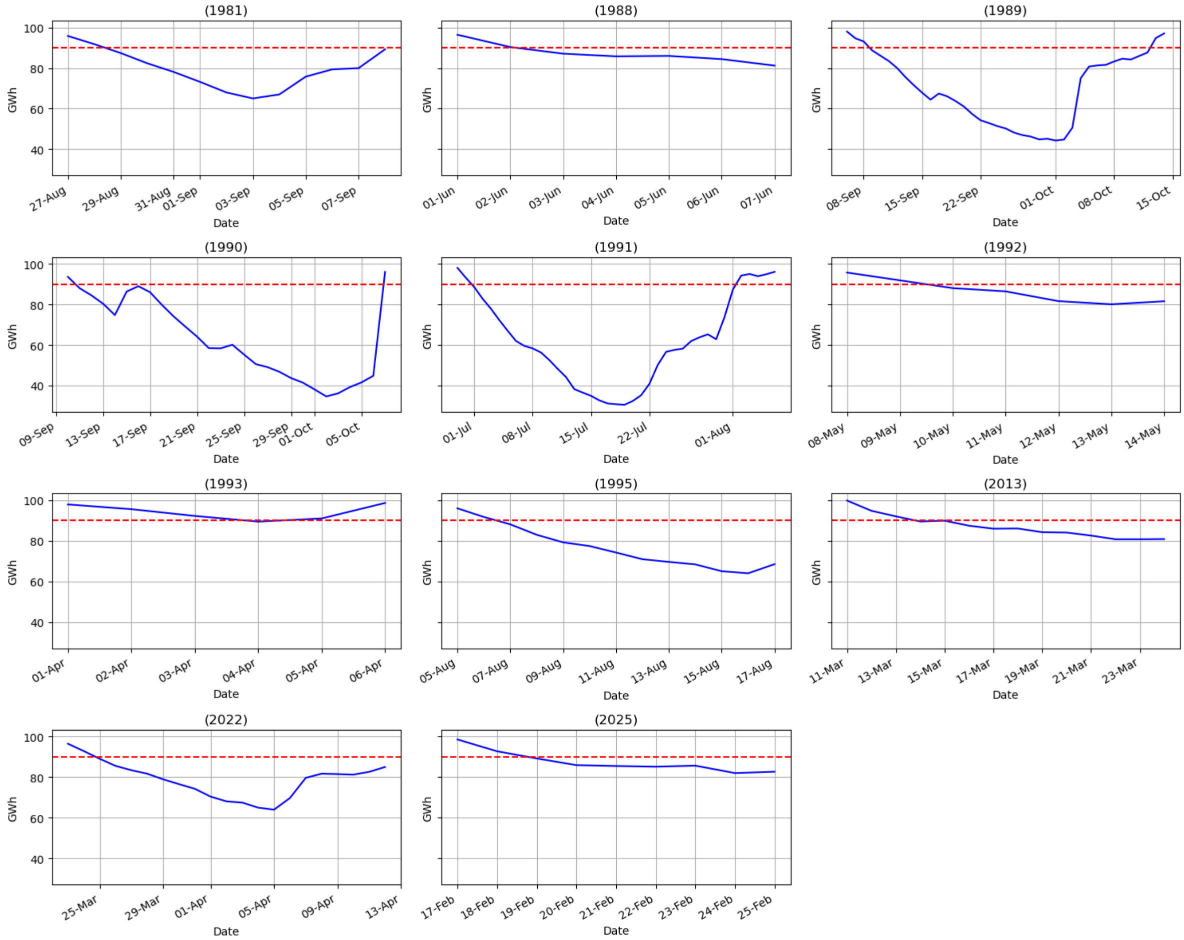
Appendix 1: Proposed changes to SOSFIP

224. The draft proposed SOSFIP amendment proposal, showing tracked changes relative to the current SOSFIP is available here: https://www.transpower.co.nz/system-operator/system-operator-consultations/invitation-comment-sosfip-consultation-2025-draft

225. In addition to the proposed changes to the SOSFIP discussed above, we propose making some minor tidy-up changes. All proposed changes are tracked.

Appendix 2: Further details on CSRB buffer

226. The chart below shows some of the instances when storage in the Waiau dropped below 103 GWh for 5 consecutive days.[73]. We can also see how in some more severe instances, the Waiau storage is pulled lower in the range and below the 90 GWh threshold. The maximum continuous period operated below 90 GWh was in 1989 which lasted 34 days (from 9-Sep to 12 Oct).



73 This data is based on NZX hydro information. There are minor differences between the NZX dataset and the hydrological modelling dataset that do not impact the salient outcomes and results.