A proposed reliability obligation to manage dry-year risk

Energy Package - Action 2.5

9 June 2026

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

New Zealand Government
Te Kāwanatanga o Aotearoa

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
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Minister’s Foreword

New Zealand has a natural advantage when it comes to renewable electricity. We already have one of the most renewable systems in the world, alongside a strong pipeline of new wind, solar and geothermal projects coming online.

We are on track for a system that is 95 to 98 per cent renewable. Over time, this will deliver more abundant and more affordable electricity for New Zealanders.

But there is one final piece of the puzzle.

To turn abundant renewable energy into reliable and affordable electricity, we need enough firm generation and fuel to back it up, especially in dry years when hydro lakes are low. The year 2024 showed what happens when we fall short – something New Zealanders should not have to accept in a country with our natural advantages. Prices rose sharply, businesses curtailed operations, and confidence in the market was eroded.

We must get ahead of that risk.

More investment in firming, such as backup winter generation and secure fuel supply, will make the system more resilient. It will also deepen hedge markets, enabling more retailers and generators to compete. That competition, in turn, supports more renewable investment. More firming unlocks more renewables, and more renewables help deliver abundant, affordable electricity.

Today, the market is not delivering enough investment in firming. This discussion document sets out proposals that will work alongside a liquid natural gas (LNG) import terminal to ensure the market invests in the firming capacity and fuel the system requires. In particular, we are consulting on a proposed new two-layer reliability obligation to strengthen incentives to manage dry-year risk, while maintaining a flexible, market-based approach.

The obligations will have substantial penalties attached to ensure parties comply and change their behaviour, rather than just accept a penalty. I intend for the substantially higher penalties that will be available to the Electricity Authority, announced in January 2026, to apply for breaches of the obligation. These will be to the higher of $10 million, three times commercial gain, or 10% of a company's turnover.

Our goal is clear: an electricity system that is abundant, renewable, reliable, and affordable, supporting economic growth, stronger businesses, and higher living standards for New Zealanders. Dry-year risk should not define New Zealand’s electricity system – and under this Government, it won’t.

This is a critical step toward delivering an electricity system that is built to last. I encourage all interested parties to engage with this consultation and help shape a framework that works for New Zealand.

Hon Simeon Brown
Minister for Energy

What are we seeking feedback on

New Zealand's Energy Package is the Government's vision for secure reliable, affordable power - investing in energy security while also building stronger, more competitive markets to withstand dry-year risk and tightening gas supply.

Action 2.5 is a core regulatory uplift of that programme: It proposes additional measures to ensure that the New Zealand electricity market has the right roles, information, rules, tools and incentives to identify and respond to evolving dry-year risk. It aims to avoid unacceptable reliability risks, damage to New Zealand's international reputation, reduced confidence in electrification and industrial investment, and significant affordability pressures on consumers. It recognises that the prior framework was not well suited to current system conditions, and that a more deliberate and future-focused approach is required.

This consultation now seeks feedback on a new two-layer reliability obligation to give greater assurance that the sector has enduring incentives to manage dry-year risk effectively, and associated implementation actions.

This consultation seeks feedback on:	
Problem Statement: additional incentives required to address dry-year risk	Confirming that due to the exposure of New Zealand's electricity system to dry-year risk as a result of reliance on weather dependent renewables, a decline in domestic gas supply, and legacy thermal generation retiring, additional incentives are required to manage dry-year risk.
Long-term obligation	Introducing a long-term obligation to strengthen incentives to secure sufficient dependable long-duration firm generation in advance where a winter energy adequacy shortfall is forecast.
Short-term obligation	Introducing a short-term obligation as a targeted backstop where a near term winter reliability risk emerges.

How to provide feedback

To make a submission on the proposals contained in this discussion paper, please complete either

- the submission form, found on the consultation page: **here** and send it to

  electricitymarkets@mbie.govt.nz

- or mail your submission to:

  Electricity Markets Policy
  Building, Resources and Markets
  Ministry of Business, Innovation and Employment
  PO Box 1473
  Wellington 6140
  New Zealand

Please reference the relevant question numbers in your feedback.

Please provide your feedback by 5pm, Tuesday, 21 July 2026

What happens next

All submissions will be read by MBIE officials. AI may be used to aid summarising submissions and distilling key points made across submissions.

Following an analysis of feedback from this consultation MBIE officials will provide advice to the Minister for Energy on the feedback received and proposed next steps.

Release of information

Submissions remain subject to request under the *Official Information Act 1982*. Please set out clearly in the cover letter or e-mail accompanying your submission if you have any objection to the release of any information in the submission, and which parts you consider should be withheld, together with the reasons for withholding the information. MBIE will take such objections into account and will consult with submitters when responding to requests under the *Official Information Act 1982*.

Private information

The *Privacy Act 1993* establishes certain principles with respect to the collection, use and disclosure of information about individuals by various agencies, including MBIE. Any personal information you supply to MBIE while making a submission will only be used for the purpose of assisting in the development of policy advice in relation to this review. As indicated above, MBIE intends to publish submissions. Please clearly indicate in the cover letter or e-mail accompanying your submission if you do not wish your name, or any other personal information, to be included in any publication of submissions or a summary of submissions.

Background: Our electricity system lacks sufficient incentives for long-duration firm energy

The winter of 2024 exposed a serious vulnerability in New Zealand's electricity market: it has not delivered enough long-duration firming

1. The winter of 2024 exposed a serious vulnerability in New Zealand's electricity market: it has not delivered enough long-duration firm energy. When hydro inflows were low, the system was left too exposed to tightening gas supply, limited thermal backup and very high wholesale prices. The consequences were felt well beyond the electricity sector. Some industrial users paused operations or closed permanently, extraordinary steps were required to maintain supply, and rising electricity prices added to pressure on household budgets and the cost of living.

2. Steps have already been taken to strengthen energy security and improve the framework, including the procurement of a new liquified natural gas (LNG) import facility. But those steps do not eliminate the problem. This consultation paper concludes that further reform is necessary. It explains why the current framework has fallen short and sets out additional measures to improve reliability and resilience. More detailed background is provided in Appendix A.

The electricity system is becoming more exposed to dry-year risk

3. New Zealand's electricity system has always been vulnerable in dry years because it depends heavily on hydro generation. When rainfall is low and there is less snowmelt, water levels in the hydro lakes are lower, so less electricity can be generated. That matters most in winter, when demand is higher because homes and businesses use more electricity for heating. At those times, other sources of generation must make up the shortfall. That task has become harder as the system has changed.

4. Much of the new generation investment in recent years has been in wind and solar. These are important sources of electricity, but they depend on the weather. Wind farms do not generate when there is little wind, and solar output drops in cloudy weather and disappears at night. That means they cannot provide the same level of backup during a long dry spell as firm generation – at least, not without long-duration storage.

5. Thermal generation now plays a smaller role than it once did. Since 2012, ~1,100MW of firm, grid-connected thermal generation which provides backup generation during dry years has been retired.[1] Huntly also cannot be treated as our only solution. Its remaining Rankine units are ageing, and do not have sufficient capacity to fill the dry-year gap alone. Uncertainty about future gas supply has also weakened confidence in gas-fired generation as a source of long-duration firm energy (although procuring a new LNG import facility will reduce that risk).

6. The result is a system that is more exposed in dry years, because there is now significantly less firm, dispatchable generation available to cover prolonged hydro shortfalls. But consumers do not pay for that risk only when a dry year happens. If the market has not delivered enough

[1] This includes Genesis' 240MW Rankine unit (2015), Contact's 400MW Otahuhu gas-fired plant (2015), Mercury's 170MW Southdown gas-fired plant and Contact's 370MW Taranaki gas-fired plant (2026).

reliable long-duration firm energy, those exposed to the wholesale market know they remain vulnerable to extreme price spikes and build that risk into contracts and charges. Consumers can therefore end up paying a dry-year premium year after year, even when conditions are normal. A lack of confidence in our ability to manage dry-year risk also shows up in reduced future economic investment. Future industries and electrification are less likely to occur if there is a perception of security of supply risks (i.e., risk of curtailment during dry years). Dry-year risk is therefore not just a reliability problem. It is also an affordability and economic growth problem.

The current regulatory framework aims to manage this risk through market incentives

7. New Zealand's wholesale electricity market is an energy-only market. Generators are paid when they generate electricity, not simply for keeping plant and fuel available. Because dry years are, by definition, rare, more costly plant that can provide generation during those events may run infrequently. Despite this, the previous wholesale market design has been expected to provide sufficient incentive for efficient investment in that type of plant for two reasons:

   - **High wholesale prices in dry years:** if a dry year occurred and supply became tight, wholesale electricity prices could rise very sharply. The idea was that, although such plant might run only rarely, it could earn a large share of its revenue in those periods.
   - **Contract revenue:** retailers and large users that would be exposed to very high wholesale prices in a dry year were expected to sign contracts in advance with plant able to provide generation in those conditions. Those contracts were meant to give investors enough certainty to support plant that might run only rarely.

8. The current[2] regulatory framework was built on that premise. It focusses on providing information about emerging risks, so generators, retailers and large users could act before conditions became critical. That has been the theory. However, in practice, the framework has not consistently delivered adequate long-duration firm energy as the system has changed and the challenges described above have become more acute.

In practice, the market has not delivered enough certainty that long-duration firm generation will be delivered

9. Several factors weakened the real-world case for new long-duration firm energy. One was the '**tenor gap**'. Plant built for dry years may run only occasionally, so contracts of 10 to 15 years, or more, may be needed to recover costs with confidence. But most buyers are understandably reluctant to commit for that long. The result is too much reliance on occasional very high wholesale prices in dry years, which is not a dependable basis on which to build new plant. Other practical considerations made the problem worse:

   - **Financing constraints:** the lack of revenue certainty then feeds directly into financing. If a project depends too heavily on occasional price spikes rather than stable contract income, lenders may be unwilling to back it. The problem can be even greater for fossil-fuel

[2] By 'current', we mean the framework that is in place today and that will remain in place until all aspects of the new regulatory framework for dry year risk - announced by the government on 9 June 2026 – are in place. This can occur following updates to legislation and (for the measures the GPS expects the Authority to consider) to Code.

projects, because some lenders are reluctant to finance assets exposed to climate and transition risks.

- **The 'investment timing' problem:** Huntly's Rankine units can still provide a large amount of long-duration firm energy from plant and fuel already in place. That weakens the case for investing in replacement generation plants while those existing units remain available. The difficulty is that those units are ageing and cannot be assumed to remain in service indefinitely. That makes the timing of replacement investment much harder.
- **Fuel availability:** long-duration firm energy depends not only on plant existing, but on fuel being available for the plant to run when needed. The events of 2024 showed that this cannot be taken for granted. Procuring a new LNG import facility will improve the availability of supply for gas-fired generation, but it does not in itself guarantee that enough fuel will be procured in a timely way.

10. The net result is that there is uncertainty that the market will bring forward enough reliable generation to provide sufficient long-duration firm energy, particularly as older generation plants become less secure. The shortfall can be significant: up to 3TWh of long-duration firm energy could be needed to insure against a significant three-month dry period. While several existing market-led energy solutions exist, the draft 2026 Security of Supply Assessment (SOSA) indicated shortfalls between the NZ-WEM security standards and expected future margins. The proposals in this paper are targeted mechanisms to ensure that the market has the right incentives to address these system-level risks.
11. Further evidence detailing the problem posed by dry-year risk, and the market's ability to address this without intervention, is included in **Appendix A.**

Further action is required

12. The incentives gap for long-duration firming is too large to ignore. Important steps have already been taken to reduce the risk, including measures to improve fuel adequacy, strengthen information, clarify roles and provide additional tools. The Government procurement of an LNG importation facility will also improve the availability of gas supply for generation. Those are all important reforms that should reduce some of the risks identified above. But they may not, on their own, ensure that enough long-duration firm energy will be delivered as the system continues to change. Further action is required.
13. This paper sets out additional measures aimed at ensuring stronger incentives are in place so that sufficient long-duration firm energy is brought forward by the electricity sector in time to support future demand growth and evolution of the future power system. Maintaining the status quo would leave New Zealand exposed to intolerable reliability risk, negatively impact our international reputation and reduce the likelihood of further electrification (including future industrial investment) and impose unacceptable affordability pressures on consumers.

Discussion questions

Q1.	Do you agree with the analysis in this chapter of why New Zealand does not currently have sufficient dry-year firming? If not, where do you disagree?
Q2.	What do you consider to be the principal remaining barriers to investment in additional dry-year firming following the recent reforms to improve fuel adequacy (Government procurement of an LNG importation facility)?

Steps already taken to mitigate the dry-year problem

14. The dry-year problem described above is a difficult one. It is also not a problem for which there is any obvious single solution. The challenge arises from a combination of physical fuel constraints, ageing thermal plant and challenges in forecasting. A multi-faceted response is therefore required.

15. With that in mind, Cabinet agreed in September 2025 to an Energy Package, *Securing New Zealand's Energy Future*, intended to enhance energy security and affordability. That package includes several measures that are already underway, or have already been implemented, to mitigate dry-year risk and address some of its underlying drivers. These are briefly summarised below.

The Energy Package

16. The Government's 1 October 2025 Energy Package recognises that the dry-year problem cannot be addressed through a single intervention. The package instead brings together several related workstreams aimed at improving fuel availability, reducing policy uncertainty, strengthening information and security-of-supply arrangements and improving the broader regulatory framework. It is a package of complementary measures, some directed at immediate and practical constraints, and others at the longer-term settings within which investment decisions are made.

Table 1: The government's 1 October 2025 Energy Package

WORKSTREAM 1: Invest in Energy Security	WORKSTREAM 2: Build Stronger Markets
• **Action 1.1:** Deliver a Liquefied Natural Gas import facility – Government will run a competitive procurement process for an LNG import facility. • **Action 1.2:** Remove capital constraints on the Mixed Ownership Model companies – remove capital constraints on the majority Crown-owned Mixed Ownership Model companies, with a clear expectation that each of these companies should separately seek out and bring forward opportunities for new generation. • **Action 1.3:** Increase New Zealand's energy supply through government energy demand – Leveraging Government's purchasing power to drive new energy projects. • **Action 1.4:** Supercharge renewable energy – Electrify NZ will double New Zealand's renewable energy by 2050 through ambitious resource management changes, the Fast Track approvals process and offshore wind legislation.	• **Action 2.1:** Reduce sovereign policy risk for investors – The Government will provide greater certainty for investors in key energy projects. • **Action 2.2:** Create a more powerful Electricity Authority – A regulator that is fit for purpose, focusing on the right things with the right tools to do its job. • **Action 2.3:** Improve transparency and efficiency of the electricity market – Amplify measures to improve electricity market transparency and information that encourages new generators and independent retailers to enter, grow and compete in the market. • **Action 2.4:** Improve gas market transparency – Ensure that gas and electricity markets have the information they need to plan for the future. • **Action 2.5:** Build reliability and resilience in the market – Strengthen the current regulatory framework to ensure that dry-year risk will not re-emerge in the future. • **Action 2.6:** Improve the business efficiency of electricity distribution businesses (EDBs).

Action 1.1: Procure a Liquefied Natural Gas import facility

17. As part of the broader Energy Package, the Government is progressing procurement of an LNG import facility. LNG is natural gas that has been cooled and liquefied so it can be transported more easily. We need LNG in our energy system because our domestic natural gas supply is falling, and other technologies that might replace it – like batteries – aren't able to provide the same level of long-duration firm generation for the energy system yet. This action recognises that the most immediate constraint to delivering security of supply in a dry year is the shortage of gas to fuel New Zealand's existing gas generation plants.

18. The Government is in effect playing a coordination role to enable the delivery of LNG on behalf of the sector. Beyond this action, the Government has been clear that responsibility for managing dry- year risk sits with the electricity sector. As discussed later in this paper, the LNG initiative will complement Action 2.5.

Action 2.5: Strengthening the regulatory framework

19. Action 2.5 of the Government's Energy Package is directed at strengthening the regulatory framework for managing dry-year risk over the medium to longer term. It reflects a recognition that the prior framework was not well suited to current system conditions, and that a more deliberate and future-focused approach is required.

Overarching objective

20. The overarching objective of Action 2.5 is to ensure that the New Zealand electricity market has the right roles, information, rules and tools and incentives to identify and respond to evolving dry-year risk.

21. Measures to strengthen roles, information and rules and tools have been agreed by Cabinet. Taken together, the package of measures will:

22. More broadly, the aim is to support an electricity system that remains secure, affordable, and sufficiently renewable to enable electrification and economic growth, even as the generation mix becomes increasingly weather dependent. This should result in long-term benefit for consumers. These changes are not intended to simply shift how gentailers manage their risk (with no noticeable impact for consumers) but rather work, as a package, to improve market liquidity, lead to investments being made sooner, and lower power bills for consumers.

23. Table 2 shows the full package of measures agreed. This includes the incentive measure this paper is consulting on.

Table 2: Measures to strengthen the dry-year regulatory framework

	MEASURES	EXPLANATION/NOTES	WHO TAKES ACTION
LEGISLATIVE CHANGES TO THE *ELECTRICITY INDUSTRY ACT 2010*			
ROLE	**Give the EA an explicit function relating to dry-year risk**	To place greater accountability on the EA and enable it to adapt more quickly to strengthen the framework to account for evolving risks	Government to legislate EA to take action per its statutory objective and functions
INFORMATION	**Require the EA to submit an annual Security of Electricity Supply Report to Minister for Energy**	To clearly inform the Government of the current and emerging risks to security of supply and whether the current regulatory settings are adequate to address the risks or if further enhancements are required	Government to legislate EA to seek review by Security and Reliability Council EA to publish annually
INFORMATION	**Require the EA to regularly review foundational security of supply monitoring framework policies**	EA to undertake regular reviews to security standards, Security Standards Assessment Document (SSAD), and Security of Supply Forecasting and Information Policy (SOSFIP)	Government to legislate EA to review the security standards and SSAD at least every 5 years and the SOSFIP every 3 years
AMENDMENTS TO THE 2024 GOVERNMENT POLICY STATEMENT ON ELECTRICITY			
INFORMATION	**Information improvements**	To ensure information provided to the market, as set out in the security of supply monitoring framework, changes dynamically with evolving security of supply risks	EA to assess, and can decide to introduce in the Electricity Industry Participation Code 2010 (the Code)
INFORMATION	**Publication of a new 'Electricity Security Opportunities Statement'**	This will ensure information on security of supply shortfalls is accessible and show options for what investment would firm that shortfall Proposed by Frontier and agreed by Cabinet	EA to set out requirements for an Electricity Security Opportunities Statement System Operator to publish annually
INFORMATION	**New market participant disclosure obligations**	Participants must disclose exit plans for firm generation (or substantive changes to entry plans), and substantive new load	EA to assess, and can decide to introduce in Code
INFORMATION	**More regular updates to Energy Demand and Generation Scenarios (EDGS)**	To ensure MBIE produces more regular electricity demand and generation scenarios, including better future load forecasts	MBIE to publish at least every 3 years
RULES AND TOOLS	**Improvements to the stress testing regime**	Stress testing (of participants' exposure to financial risk relating to dry-year exposure) to be improved, so each large customer, and the EA, is better aware ahead of time (and can choose to take action)	EA to assess, and can decide to introduce in Code Participants required to undertake tests and report to EA
RULES AND TOOLS	**Improvements to market liquidity**	Assess liquidity in hedge markets and the effectiveness of market-making obligations. Consider strengthening or extending market-making obligations where needed	EA to assess, and can decide to introduce in Code
RULES AND TOOLS	**New standardised risk management products**	Introduce new standardised long-duration cover contracts to enable customers to manage risk. These will be similar to the standardised super-peak contracts currently available, but will cover longer durations	EA to assess, and can decide to introduce in Code
A RELIABILITY OBLIGATION (The subject of this consultation)			
INCENTIVES	**Introduce a new reliability obligation**	A new Winter Energy Reliability Obligation (an *ex ante* obligation) covering: short-term fuel procurement, and long-term energy adequacy	MBIE to consult on options

Roles

24. The Government will amend the Electricity Industry Act 2010 to give the Electricity Authority an explicit statutory function relating to dry-year risk. This will ensure clarity in regulatory roles and responsibility for ensuring the sector addresses evolving dry-year risk within the electricity system. The expected outcome is a more responsive regulatory regime that acts to ensure any emerging or evolving dry-year risk is identified in advance and with a proportional and timely response to mitigate undesirable market outcomes.

Information

25. One important strand of work has focused on improving the information available to market participants about emerging dry-year risk. As noted above, the current framework relies heavily on forward-looking assessments and warning signals to prompt a market response. If those assessments do not adequately reflect evolving system conditions, the resulting information may not be sufficiently clear, credible or useful to support efficient investment and contracting decisions.

26. For that reason, work has already been undertaken to strengthen the Security of Supply Assessment (SOSA), produced by the System Operator, and the broader security of supply framework. The aim is to provide greater clarity and confidence in security of supply assessments, improve visibility of emerging shortfalls, and better reflect demand patterns, renewable variability, fuel constraints and other evolving system risks. These changes are intended to ensure that dry-year risk is identified earlier, assessed more robustly, and communicated clearly to market participants, regulators, policy makers and the public.

Rules and tools

27. A second strand of work has focused on the rules and tools that support the management of dry-year risk. The purpose is to ensure that the relevant legislative settings, Code provisions and associated framework remain fit-for-purpose as the electricity system evolves.

28. The Electricity Authority is currently progressing several initiatives in this area, including improvements in the market stress-testing framework, investigating standardisation of long-duration risk management products and enhancement of market-making settings.

The remaining gap: Incentives and clear responsibilities

29. While the measures above strengthen roles, information, rules and tools, they do not by themselves ensure that market participants face sufficient commercial incentives to procure, maintain, or contract for long-duration firm energy at the system level.

30. Better information and clearer accountability help the market recognise emerging risks earlier, but they do not create bankable revenues for long-duration firming. Without stronger price or contract signals, participants are likely to delay investment, under-contract, or run down fuel and maintenance capability. Ultimately, this will result in the market remaining "on the edge" and prices remaining elevated. While the measures outlined above are valuable changes to market settings, consumers will be unlikely to see lower power bills as a direct result without further intervention.

31. The Government is therefore consulting on a new regulatory obligation to ensure the sector has a clear incentive (via a responsibility) to deliver adequate long-duration firm energy, and the fuel to run it. This will help ensure the electricity market delivers adequate dry-year resilience for consumers and the wider economy as the system evolves, while avoiding unnecessary central procurement and preserving efficient dispatch.

32. The remainder of this discussion document sets out the proposed options intended to strengthen responsibilities so as to:

- close the revenue-certainty gap for long-duration firming
- preserve a market-led approach to investment and operations
- allocate risk efficiently between investors, generators, retailers and consumers
- minimise long-run cost to consumers.

33. The focus of the options that follow is therefore not on improving the identification of dry -year risk, but on how clearly identified risks should translate into earlier and more reliable market action. The aim is to strengthen ex ante incentives and responsibilities in a way that preserves market- led investment, risk management and efficient dispatch, while reducing reliance on late, or emergency responses. The following sections set out proposed incentives designed to achieve this.

Changes through several mechanisms will give effect to the package

34. Changes through several mechanisms will give effect to the package:

- Changes to the Electricity Industry Act 2010 (the Act) to (1) give the EA an explicit function to ensure effective management of dry-year risk, (2) introduce minimum requirements for regular reviews by the EA (and where relevant the System Operator) of key security-of-supply monitoring frameworks and methodologies, and (3) require the EA to report to the Minister for Energy annually on current and emerging security-of-supply risks.
- Updates to the Government Policy Statement for Electricity (GPS), issued in October 2024 under section 17 of the Electricity Industry Act, with clear expectations on the EA to increase its focus on the management of dry-year risk. The GPS signals the EA should focus on improving the security of supply information as dry year risk evolves, and consider improvements to market participant disclosure obligations, the stress testing regime, to support market liquidity and risk management. The System Operator will publish a new Electricity Security Opportunities Statement, and MBIE will publish more regular updates to the Energy Demand and Generation Scenarios (EDGS).
- A potential new two-layer reliability obligation that will incentivise the larger market participants to ensure sufficient fuel, and long-duration firm energy (or demand response), to cover dry-year risk (the subject of this consultation paper).

Discussion questions

Q3.	Do you agree that, despite the recent reforms to improve fuel adequacy, information, roles and tools, further measures are still needed to strengthen incentives to invest in dry-year firming? If not, please explain why not?
Q4.	Do you agree that there is value in building new measures on existing regulatory architecture, rather than creating an entirely new regime from first principles? Why or why not?

Proposed option: A winter energy reliability obligation

A two-layer winter energy reliability obligation would strengthen incentives for market participants to secure enough long-duration firm energy to efficiently get the electricity system through a dry winter.

Introduction: what the reliability obligation aims to achieve

35. Together with actions already underway to improve dry-year resilience, the reliability obligation is intended to improve the resilience of the power system. But it's not all about resilience and minimising risk. It is also expected to support increased renewable investment, stronger competition, and downward pressure on electricity prices. This is because:

    - Firming resources are currently limited and not always accessible to all market participants. A reliability obligation would strengthen incentives to contract for, and invest in, firming capacity, increasing its availability to the wider market. Greater access to firming would enable independent generators and retailers to back new renewable generation and compete more effectively, supporting increased renewable penetration and competitive pressure on prices.
    - The risk of scarcity during dry-year conditions introduces a risk premium into contract markets, which flows through to retail prices even in average hydrological conditions. By reducing the likelihood and severity of scarcity events, a reliability obligation would be expected to reduce this risk premium and place downward pressure on electricity prices.

36. Of course, increasing reliability is not without cost. Setting the obligation too high could result in over-investment in firming resources and higher overall costs. The objective is therefore to strike an appropriate balance.
37. However, the current system appears to operate with very limited buffer which risks underestimating the asymmetric cost of supply shortfalls and the wider impacts of scarcity. In particular: (1) the economic and social costs of supply shortfalls are significantly greater than the costs of maintaining a modest level of surplus capacity; (2) scarcity events have economy-wide impacts that extend well beyond the electricity sector; and (3) improved access to firming capacity can have dynamic benefits by supporting renewable investment, competition, and electrification over time. In short, more firming generation is the key to more renewable, reliable and affordable electricity.

Overview of the reliability obligation

38. The proposed reliability framework has two layers. The first would operate five years ahead of the relevant winter and apply when the Security of Supply Assessment (SOSA) shows that existing and planned physical cover is likely to be insufficient. At that point, it would identify the forecast shortfall and require large wholesale purchasers to secure additional dependable winter cover ahead of time to meet their respective load requirements. This would have the effect of requiring wholesale purchasers to cover their own risk plus a portion of the overall system-level risk should it emerge. This would lead to increased contracting for future winter energy solutions, providing greater revenue certainty for investors.
39. In most cases, that longer-term mechanism should address the relevant risk before it becomes acute. But it would not eliminate dry-year risk altogether. The situation 'on the ground' each year

may turn out differently from what was expected. For example, a significant generator could face an unexpected and prolonged outage, or gas availability could be well below what was expected a couple of years earlier. A system that appears comfortably positioned, based on multi-year forecasts, may therefore still approach winter in a materially more stressed position. For that reason, a short-term residual mechanism will also be required. The proposed reliability framework would therefore include:

- a **longer-term, investment focused, obligation**, which would operate some years before the relevant winter, when the security of supply outlook shows that winter energy margins are likely to fall below an acceptable tolerance level between three and five years in the future; and
- a **short-term, operational focused, obligation**, which would operate in the months leading up to the relevant winter when a defined operational trigger indicates that, despite the operation of the longer-term mechanism, a residual dry-year reliability risk has emerged.

40. The two layers are therefore directed at different aspects of the problem: the first at improving preparedness including investments ahead of time, and the second at requiring a nearer-term response if conditions deteriorate to an unacceptable level despite those earlier steps.

41. Both layers can be understood as forms of insurance against dry-year risk. In each case, the obligated parties would be required to put arrangements in place to reduce the likelihood and consequences of the system entering a materially stressed winter position without sufficient dependable contracts for, or own, long-duration firm generation. As with any insurance arrangement, that protection would come at a cost, and in some cases that outlay may be incurred even though the feared dry-year conditions do not ultimately arise. But that does not make the expenditure unnecessary or wasteful. The fact that an insured event does not occur does not mean it was imprudent to guard against it. The value lies both in the protection available if the risk eventuates and in the greater confidence and resilience that comes from knowing it is in place.

42. Of course, the principal payoff arises when dry-year conditions *do* in fact materialise. If the two-layer framework succeeds in increasing the amount of dependable long-duration firm generation available to the system when it is genuinely needed, the adverse consequences should be materially less severe. Within the electricity market itself, wholesale prices should be lower and less volatile in a stressed winter, less demand should go unmet, and the likelihood of forced curtailment and emergency intervention should be reduced. Those 'in market' benefits are likely to be considerable in their own right.

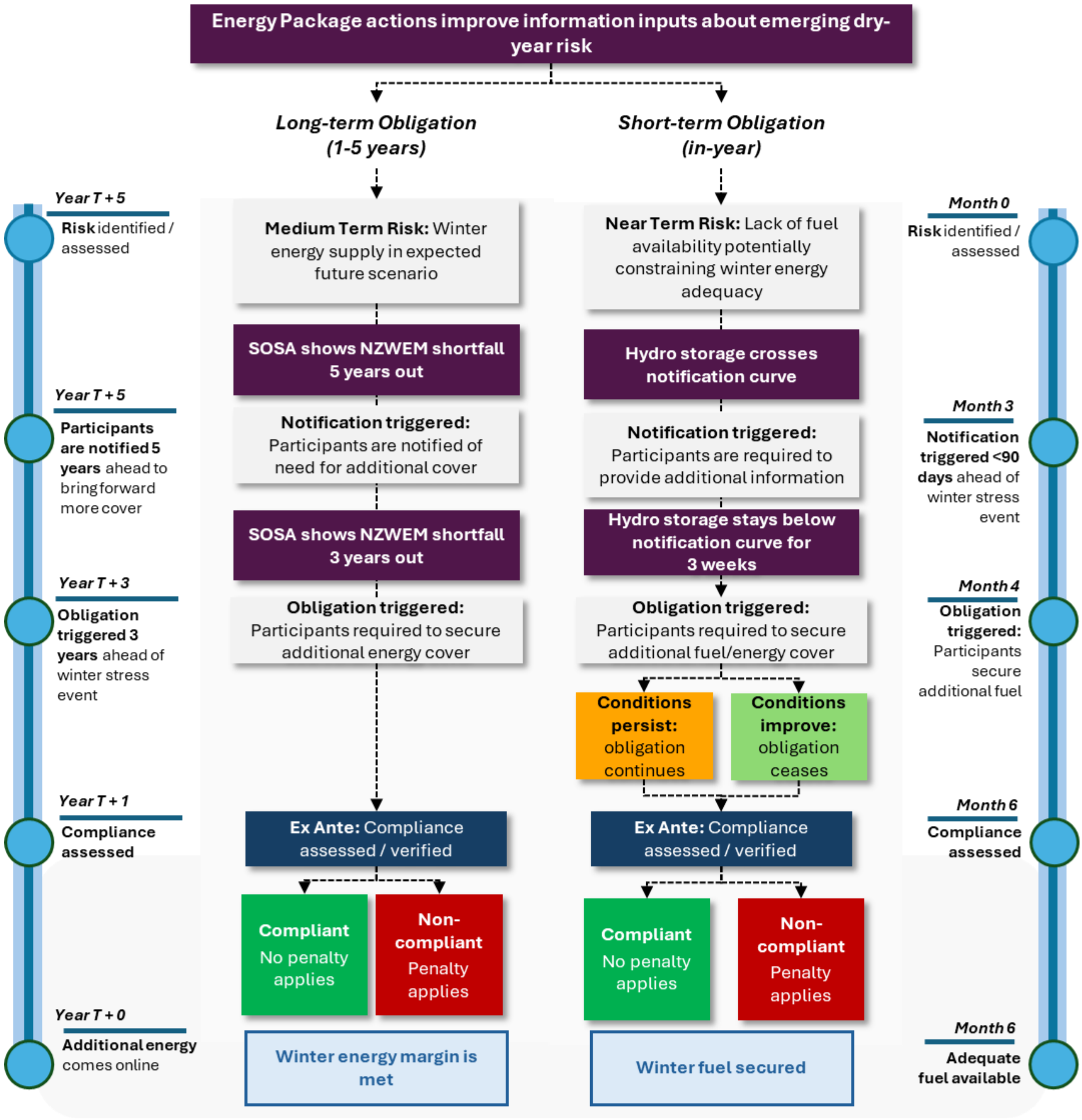
43. As noted in the introduction above, the potential benefits extend well beyond the electricity sector. By reducing the severity of dry-year conditions, the framework may help avoid the closure or curtailment of energy-intensive businesses, reduce the risk of associated job losses, and lessen wider economic disruption. It may also have substantial positive spillover benefits for future industries and potential new connecting parties looking to New Zealand as a destination that provides reliable, affordable, renewable electricity. There are also benefits for households, including by easing upward pressure on retail prices and the cost of living, which may be especially important for consumers already experiencing energy hardship. Those benefits are potentially vast and lie at the heart of this policy proposal.

44. Consequently, the success of the framework should ultimately be judged by how effectively it addresses the present shortfall in long-duration firm energy, and how well it reduces the severe costs that dry-year conditions can impose on consumers and the wider economy. There may be several different ways in which that result is achieved – including additional generation, greater

demand response, fuel procurement, storage or other arrangements. The critical question is not necessarily the form the response takes, but whether the framework succeeds in materially reducing the underlying dry-year risk, however the means.

45. As Figure 1, below, illustrates, the proposed two-layer reliability framework builds on reforms already underway and adds targeted mechanisms to address the remaining reliability shortfall.

Figure 1: Overview of two-layer energy reliability incentive framework



Long-term obligation: ensuring adequate energy resources are available to meet expected winter demand

46. When New Zealand's energy-only market was designed, the expectation was that participants would respond efficiently to price signals and make their own operational and investment decisions accordingly. Over time, the combined effect of those decisions was expected to be sufficient to meet the relevant security and reliability standards. In particular, the prospect of elevated wholesale prices when supply was short – and the incentive that would create for load to contract ahead with parties able to avoid that exposure – was expected to support an efficient level of long-duration firm energy.

47. As discussed earlier, that expectation has not proved fully reliable in practice. A range of factors weakens both the incentive and the ability of participants to secure sufficient dry-year protection. Several reforms have already been taken or proposed in response, including measures to improve information, strengthen fuel availability, and clarify roles, responsibilities, rules and tools. Those reforms should improve market functioning. But they may still not be enough, on their own, to ensure that sufficient dependable long-duration firm generation is brought forward when it is needed.

48. Despite these steps, we remain concerned that the market may still fall short from a system-wide perspective. Individual participants, acting rationally, may have weaker incentives to secure sufficient long-duration firm energy in advance than desired by consumers. Put simply, they may invest in too little long-duration firm energy or do so too late. This may be the case whether the response takes the form of new firming investment, demand response, fuel procurement, storage, or another dependable arrangement capable of reducing the risk and consequences of a dry year.

49. Given this, a more direct obligation to invest in a way that reduces dry-year risk is proposed; information alone is insufficient. Accordingly, if the security of supply outlook indicates that expected energy is likely to be insufficient, the relevant parties will be required to secure additional dependable winter energy cover in advance. The aim is not to displace the market or prescribe a particular solution, but to strengthen incentives to respond where ordinary market signals alone are unlikely to be enough.

50. As noted earlier, the potential benefits of such an approach are substantial. A stronger obligation to secure dependable long-duration firm energy ahead of time should reduce the likelihood and severity of dry-year shortages, lessen reliance on sharply elevated wholesale pricing in stressed periods, and improve the overall resilience of the system. Over time, it should also reduce the potentially profound economic and social costs associated with unmet demand, forced curtailment and prolonged system stress.

51. Those benefits need to be weighed against significant costs and risks. The long-term obligation would involve non-trivial compliance, administration and monitoring costs. It would also depend on forward-looking adequacy assessments, which are necessarily uncertain and may be contested. Difficult design choices would arise around forecasting, timing, allocation, compliance pathways, penalty calibration, and whether any safety-net response is needed if a shortfall persists. If poorly designed, the regime could add cost and complexity without materially improving winter preparedness.

52. However, on balance, we consider that this obligation should be implemented. Existing settings do not appear to provide incentives that are sufficiently strong or reliable to deliver the level of long-duration firm generation the system may require. A long-term obligation would not be simple, nor would it eliminate dry-year risk altogether. However, a more direct mechanism to

strengthen incentives to secure long-duration firm energy in advance should improve system resilience, reduce dry-year risk, and support more stable outcomes for consumers. It would also provide a meaningful degree of 'peace of mind'.

53. The focus of consultation should therefore be on how such a regime could best be designed to maximise its benefits and manage its risks. In particular, views are sought on whether a long-term obligation can be targeted with sufficient accuracy to address genuine winter energy adequacy shortfalls, and on how it can strengthen incentives without distorting investment behaviour or competition. Perspectives are also welcomed on how key design features – including forecasting, allocation and penalties – should be structured to ensure that the mechanism is proportionate, credible, and workable in the New Zealand context.

Summary of the long-term obligation

54. Box 1, then Figure 2 below, summarise how the long-term obligation could function in practice. It illustrates the main steps in the mechanism, from the identification of a forecast winter adequacy shortfall through to the allocation of obligations to individual entities, compliance, and enforcement, and highlights some of the principal design considerations that would arise at each stage.

Box 1: LONG-TERM OBLIGATION

A forward-looking mechanism to strengthen incentives to secure reliable long-duration firm energy in advance, rather than waiting for shortages to emerge.

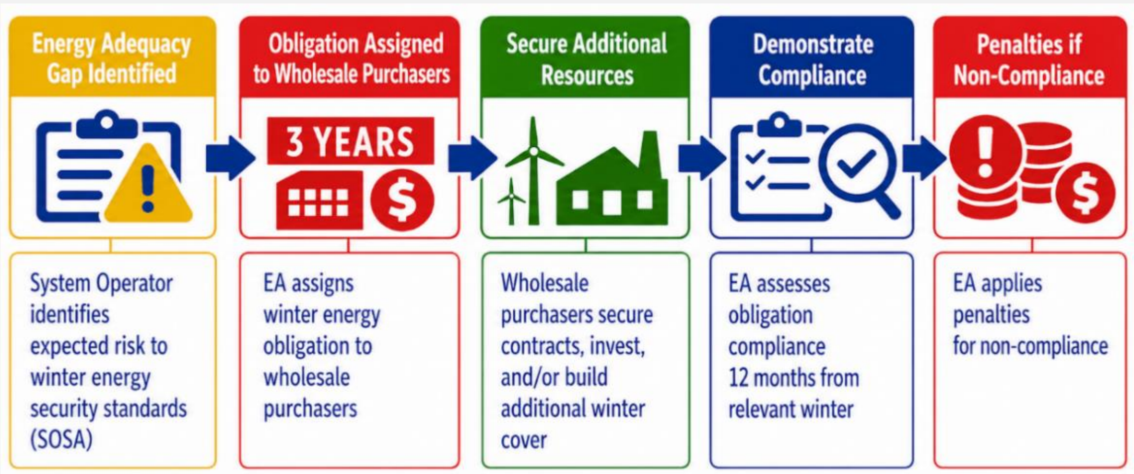
Overview

A long-term, *ex ante* obligation under which large wholesale purchasers would be required to secure sufficient qualifying long-duration firm energy if the SOSA forecasts that winter energy margins fall below the security standard. It is intended to strengthen incentives to secure dependable cover ahead of time, while preserving a market-led approach to investment, contracting and demand response.

What it seeks to achieve

- Improve winter resilience by increasing the amount of dependable cover in place before dry-year conditions emerge.
- Ensure dry-year risk – and the resulting reliability and price impacts – is at an efficient level.
- Efficiently minimise the likelihood of shortages, curtailment and broader economic disruption.
- Strengthen incentives to invest in, retain or contract for resources capable of providing reliable winter support.

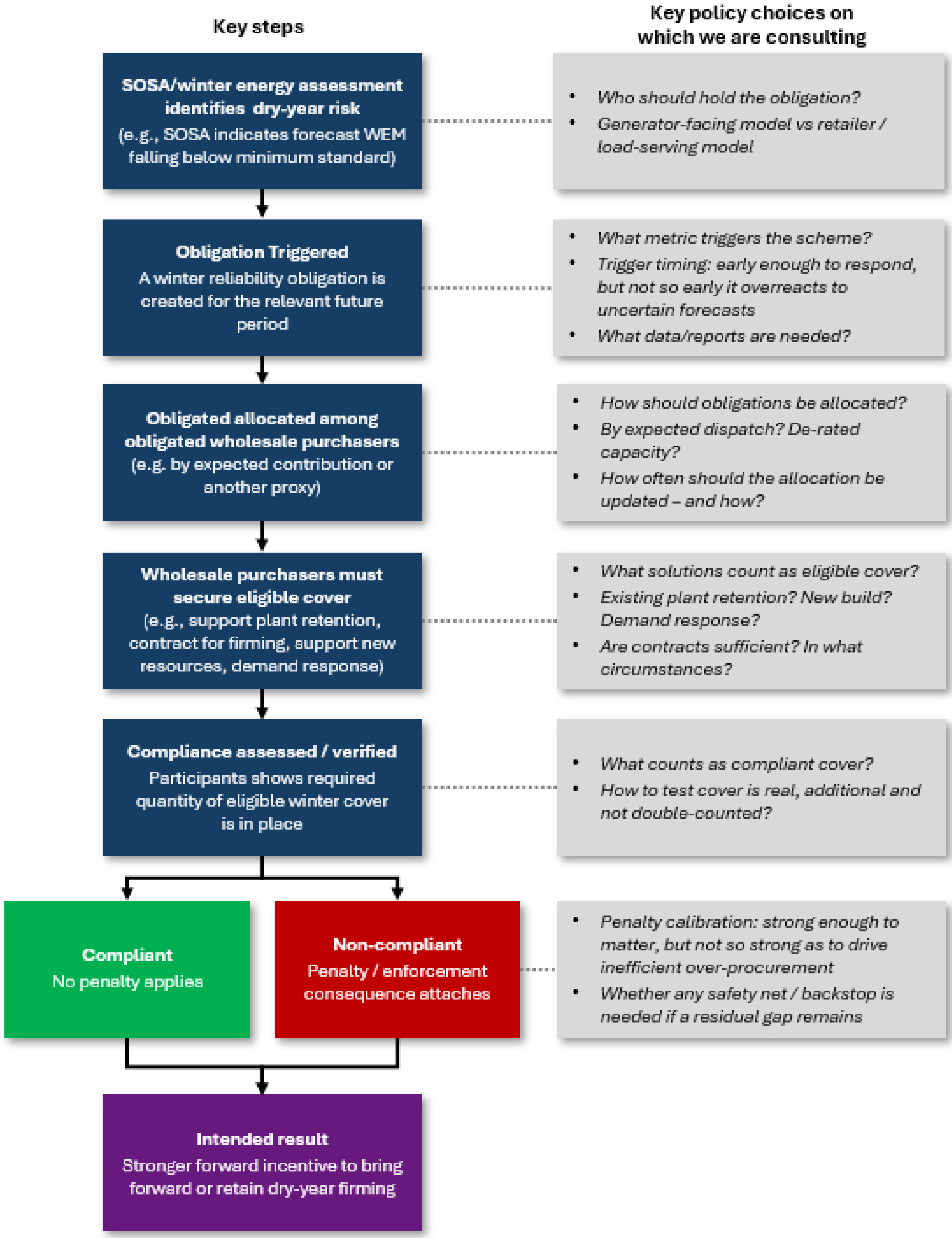
How it works (in simple terms)



Obligation features

- **Trigger:** Based on the New Zealand Winter Energy Margin, assessed through the SOSA's Expected Future Scenario and approved by the Electricity Authority.
- **Obligated entities:** Large wholesale purchasers whose aggregate load over the winter period exceeds the *de minimis* threshold.
- **Obligation allocation:** Based on each obligated purchaser's share of expected winter demand.
- **Qualifying cover:** Verifiable winter energy cover, which may include existing generation plant, generation under contract, contracted demand response, or other dependable arrangements that qualify under the regime.
- **Compliance assessment:** The Electricity Authority would assess whether each obligated purchaser has secured enough qualifying cover 12 months from the relevant winter period.
- **Penalty trigger:** Failure to secure sufficient qualifying cover to meet the purchaser's allocated obligation.

Figure 2: Key steps and policy choices relating to the long-term obligation



Who holds the obligation? Large wholesale purchasers would be responsible for securing winter energy reliability on behalf of consumers

55. It is proposed that the long-term obligation would be placed on large wholesale purchasers whose aggregate load over the winter period exceeds a defined *de minimis* threshold.

56. Wholesale purchasers procure electricity for consumers and manage exposure to energy prices through their purchasing and contracting decisions. This could also include the largest industrial customers, where their aggregate load over that period exceeds the threshold.

57. We recognise that wholesale purchasers do not control every element relevant to winter adequacy, and that the actions affecting long-duration firm energy are distributed across the system. Even so, they are the parties that assemble the portfolio of supply and contractual arrangements on which consumers rely. If the policy objective is to ensure that sufficient dependable winter cover is secured in advance, it is reasonable to place that responsibility on the parties procuring supply for load.

58. Excluding smaller wholesale purchasers reflects principles of materiality, proportionality, competition, and regulatory efficiency. Entities that are too small to materially affect system reliability, whose inclusion would impose disproportionate compliance costs, or whose participation could chill competition and innovation are unlikely to improve reliability outcomes. Limiting coverage to material, system-relevant participants preserves clear accountability, supports market dynamism, and avoids unnecessary regulatory overhead.

59. On an initial basis, the *de minimis* threshold could be set at 500GWh of aggregate load over the winter period (01 April to 30 September). A threshold of that kind would help ensure that the obligation falls on purchasers with a sufficiently material exposure to winter energy adequacy risk, while avoiding disproportionate compliance costs for smaller purchasers and unnecessary barriers to entry or expansion. In practice, this would result in the long-term obligation currently applying to the four large gentailers (Contact, Genesis, Mercury and Meridian) and the New Zealand Aluminium Smelter.

60. A threshold framed by reference to aggregate load over the winter period is preferable to one based on annual consumption or instantaneous peak demand. The policy concern is whether sufficient dependable cover is in place to manage winter energy scarcity and dry-year conditions over time. That is fundamentally an energy adequacy problem across the winter period, rather than simply a question of year-round consumption or short-duration peak capacity. A winter-period load threshold therefore better aligns liability with the conditions the obligation is intended to address.

61. For that reason, the threshold should be assessed by reference to a party's aggregate load across the winter period as a whole, rather than by reference to individual sites or contracts viewed in isolation. The regime should also be designed to prevent artificial fragmentation of load to avoid liability. We welcome views on the appropriate *de minimis* threshold, including whether 500GWh over the winter period (01 April to 30 September) is the right starting point.

62. Placing the obligation on large wholesale purchasers may require these parties to secure more cover than they might otherwise have secured, or at least to secure it sooner than they otherwise would. This would not eliminate dry-year risk altogether, but it would reduce its severity and lessen the likelihood that the system remains exposed until conditions tighten. That would necessarily involve additional costs. However, the alternative is to leave more of the system exposed until later, with the result that the costs of a dry winter are borne in a more acute and disorderly form.

63. As noted earlier, the adverse consequences associated with dry years can be stark. They may include elevated wholesale prices, unmet demand and other consequences within the electricity market, as well as wider economic disruption beyond it. The basic premise of the obligation is that it is preferable to incur an upfront cost earlier and more deliberately to help ensure adequate cover is in place than to leave consumers and the wider economy more exposed to those outcomes.

How would a shortfall be identified? Winter energy adequacy would be assessed using the SOSA and the New Zealand Winter Energy Margin

64. A central design question concerns the method by which the Electricity Authority, as scheme administrator, would determine whether a winter energy adequacy shortfall exists and, if so, its size. We propose that the Authority should use the New Zealand Winter Energy Margin, as forecast through the Security of Supply Assessment (SOSA), for that purpose. That approach would direct the scheme toward expected energy adequacy across the winter as a whole, rather than toward momentary capacity shortages in particular trading periods.

65. The relevant reference case would be the '*Expected Scenario*'. That scenario would reflect the System Operator's assessment of the most likely future conditions at the time of analysis. The System Operator would consult on that scenario, and the Authority would approve it. The credibility of the obligation will depend heavily on the assumptions used to identify any shortfall and measure its magnitude.

66. On that basis, the Expected Scenario, together with the applicable security standard and other relevant assumptions, would determine whether the expected winter energy margin remains sufficient. If it does, no obligation would arise. If it does not, the shortfall would be identified and quantified for the purposes of the regime. This approach offers two main advantages:

- First, it would build on an existing framework that is transparent, established and familiar to market participants.
- Second, it would create a clearer link between the conclusions of the SOSA and the operation of the reliability framework. Instead of merely signalling an emerging adequacy problem, the framework would identify the existence and scale of any winter energy shortfall in a way that could support a concrete regulatory response ahead of the relevant winter.

67. The key output of that assessment would therefore be the size of the forecast winter energy adequacy shortfall, if one exists, as determined by reference to the *Expected Scenario*, the applicable security standard, and the other assumptions used in the SOSA. That quantified shortfall would then provide the basis for any allocation of obligations across liable parties – a process we discuss below.

When would the obligation arise? The obligation would be signalled and enforced through a staged process ahead of the relevant winter

68. A separate design question concerns timing. A long-term obligation of this kind will only be effective if it gives obligated parties enough time to respond before the relevant winter arrives. That is one of the main advantages of an *ex ante* approach. It focuses attention on securing sufficient long-duration firm energy in advance, rather than leaving the system exposed and merely hoping that tight supply conditions do not eventuate. The timing decision involves a clear trade-off:

- If the signal is given **too early**, the forecast may still be highly uncertain. That creates a greater risk that the obligation is based on a shortfall that does not ultimately emerge, or fails to identify one that does.
- If the signal is given **too late**, obligated parties may have insufficient time to respond through investment, contracting, retention decisions, demand response, or other measures.

69. The timing of the obligation must therefore strike a balance between giving parties enough notice to respond and maintaining sufficient confidence that the identified shortfall is real and material. Our proposed approach would involve three stages in the lead-up to the relevant winter:

    - First, a **formal warning notification** would be issued **five years** out if the expected Winter Energy Margin falls below the lower New Zealand Winter Energy Margin threshold. That warning would signal that a long-term obligation is likely to arise unless the outlook improves.
    - Second, a **formal obligation notification** would be issued **three years** out if the expected Winter Energy Margin is below the threshold. At that point, the identified shortfall would be translated into a binding obligation. Obligated parties would then be required to secure sufficient qualifying cover to meet their allocated share of it.
    - Third, an **obligation assessment** would be completed **one year** out. At that point, the Authority would assess whether each obligated party had complied. If a party had failed to secure the required level of qualifying cover, penalties would apply in accordance with the design of the regime.

70. This staged approach aims to provide a more proportionate way of dealing with forecast uncertainty. It would distinguish between an earlier period in which the market is expected to respond to a developing signal and a later point at which the shortfall has become sufficiently proximate to justify stronger consequences. It would also preserve a role for market-led adjustment before the formal obligation takes effect.

71. The final design would, however, need to make clear how those stages interact if the adequacy outlook changes materially between the initial warning, the formal obligation, and the later compliance assessment. Forecasts will inevitably involve uncertainty. Projects may slip. Hydrology and demand may evolve differently from expectations. Outages or fuel constraints may emerge. Large loads may also enter or leave the system.

72. That creates a genuine limitation. If obligations remain fixed from the outset, participants may fully comply, yet the system may still face a shortfall if conditions worsen after the initial forecast. But frequent revisions to obligations would expose participants to significant compliance costs driven by forecast volatility rather than genuine structural change. The regime will therefore need to address forecast uncertainty expressly and strike an appropriate balance between participant certainty and the risk of residual inadequacy.

73. It should also be noted that the obligations would not arise in a vacuum. Market participants should already be monitoring the SOSA and dry-year risks on an ongoing basis. They should also be planning accordingly. In that sense, the obligation would not be expected to confront participants with an entirely unforeseen problem. Its practical effect would instead be to require participants to move more decisively, and on a more reliable timetable, in relation to options that should already be under active consideration.

74. We welcome feedback on whether this staged approach strikes the right balance. We also welcome views on whether the proposed lead times are appropriate, and on how the regime should respond if the adequacy outlook changes materially between the initial warning, the formal obligation and the later compliance assessment.

How would the obligation be allocated amongst participants? Obligations would be attributed to entities in proportion to expected winter demand

75. Where a winter energy adequacy shortfall is identified and the long-term obligation is triggered, the total obligation would be allocated across the obligated wholesale purchasers by reference to each purchaser’s share of expected winter demand. In other words, if a purchaser accounts for half of the forecast winter load, it would assume responsibility for covering half of the adequacy shortfall. That would provide a straightforward basis for apportioning responsibility among the parties within the scheme.

76. Importantly, the obligated cohort would need to cover 100 per cent of the identified adequacy shortfall. It would not be sufficient for those purchasers to cover only the share of the shortfall corresponding to their share of total winter demand, because that would leave part of the shortfall unaddressed. Accordingly, even if the purchasers within the scheme account for less than 100 per cent of expected winter demand (due to the *de minimis* threshold), they would, as between themselves, be required to secure enough cover to close the full forecast shortfall.

77. That necessarily gives rise to equity considerations. Wholesale purchasers outside the scheme would not be subject to any direct obligation, even though they would also benefit from the resulting reduction in system-wide dry-year risk. That may be acceptable if the alternative would create disproportionate complexity or barriers to entry and expansion as discussed earlier. Nonetheless, it would mean that some load contributing to the adequacy shortfall would not be subject to any direct obligation to help close it.

78. Subject to that qualification, allocation by expected winter demand would broadly align responsibility within the scheme with the scale of each purchaser’s load. Purchasers with a larger share of expected winter demand would face a correspondingly larger obligation, while those with a smaller share would face a smaller obligation.

79. Several practical issues would still need to be addressed through detailed design. These include demand forecasting error, changes in customer load over time, customer switching after obligations have been allocated, and the treatment of spot-exposed consumers and smaller wholesale purchasers below the threshold. The allocation framework would need to address those issues in a way that is workable and proportionate, without undermining retail competition. We welcome submitters’ feedback on these design points.

What must obligated parties secure? Wholesale purchasers would be required to hold verifiable winter energy cover where a system shortfall is identified

80. Where the long-term obligation is triggered, each obligated wholesale purchaser would be required to secure sufficient verifiable winter energy cover to meet its allocated share of the identified adequacy shortfall. The central question then becomes what kinds of resources can shift the margins and close the shortfall assessed by the SOSA?

81. The regime should focus on achieving this outcome, rather than prescribe a single type of technology or commercial arrangement. The relevant issue is whether the wholesale purchaser

can point to arrangements that credibly improve the system's ability to maintain supply over the relevant winter period. In that sense, qualifying cover could include generation, demand response, contractual rights or other arrangements that provide dependable winter energy support.

82. We welcome feedback on what forms of cover should qualify under the regime, and on the evidential standard that should apply.

How would compliance be assessed? The Electricity Authority would assess whether each wholesale purchaser had secured enough qualifying cover

83. The long-term obligation would need to be supported by a clear compliance assessment framework. At the relevant assessment date, the Electricity Authority would need to determine whether each obligated wholesale purchaser had secured sufficient qualifying winter energy cover to meet its allocated share of the identified adequacy shortfall.

84. In many cases, a purchaser may meet some or all of that obligation through its own generation portfolio. In other cases, it may do so through contracts or other arrangements with generators, large consumers, or other providers. In either case, the Authority would need to be satisfied that the purchaser had secured rights to a sufficient volume of qualifying cover over the relevant period. The assessment would therefore need to address three matters:

- First, whether the purchaser had **secured enough cover** in quantity terms.
- Second, whether the cover was **of a kind that qualifies** under the regime.
- Third, whether that cover had in fact **been allocated to the purchaser**, for that period, in a way that avoids double counting.

85. Where the purchaser relies on its own generation, the compliance question would be whether that generation can properly be treated as qualifying cover for the relevant period, having regard to the rules of the regime.

86. Where the purchaser relies on arrangements with others, the question would be whether those arrangements give the purchaser a sufficiently clear and enforceable entitlement to the relevant cover. Additionally, for the obligation to be successful, the arrangements would need to confer a sufficient incentive on the seller to tilt investment cases that aren't currently in the Expected Scenario of the SOSA.

87. The Authority's role in the context of the long-term obligation would not be to conduct a full operational assessment of every underlying asset or arrangement. The purpose here is to assess whether sufficient qualifying cover has been secured ahead of time. The emphasis would therefore fall on the purchaser's own position, and on whether it has established, by reference to its generation portfolio, its contractual arrangements, or both, that the required cover has in fact been procured.

88. The compliance framework should therefore specify what an obligated purchaser must provide in order to establish that it has secured sufficient qualifying cover by the assessment date. It should also set out how the Authority is to approach more difficult questions of classification, attribution, shared arrangements, portfolio treatment, hydro treatment, and double counting. We welcome views on these design points.

What happens if participants do not comply? Penalties would be imposed if a party does meet its obligation

89. Penalties would be a central part of the scheme, because they are what would give the obligation practical force. All penalties that apply would be administered and enforced by the Electricity Authority.

90. The obligations must have sufficient penalties attached to ensure parties comply and change their behaviour, rather than just accept a penalty. The Electricity Authority will soon have greater penalties available, which could be applied to parties breaching their obligations. The penalty for parties breaching their obligations could be the higher of up to $10 million, or three times the commercial gain, or 10% of a company's turnover.

91. Penalties would need to be large enough to influence behaviour and deter strategic under-provision, but not so large that they distort investment decisions or encourage inefficient over-procurement. That calibration would not be straightforward:

    - If the penalty is **too low**, participants may treat it as another cost of doing business and absorb it, or pass it through into contract prices and other commercial decisions, without materially changing behaviour. Consumers may then bear the cost of the regime without receiving much additional winter cover in return.
    - If the penalty is **too high**, participants may over-invest, over-contract, or preserve inefficient cover beyond what is needed for system security, with those costs also likely to be passed through over time.

92. This framing illustrates a spectrum of different options and design choices, as shown in Table 3. We propose the penalty settings are configured to tilt investment decisions, not force or be limited to reputational impacts alone. The choice to tilt investment decisions should act to weight future pipeline options to those that are more desirable to support system reliability.

93. To tilt investment decisions, one possible starting point would be a dollar-per-MWh shortfall charge for any unmet portion of a participant's allocated obligation. That would tie the penalty directly to the scale of the compliance failure and give participants a clearer indication of the consequences of under-delivery. An approach of that kind would also have the advantage of relative transparency: the greater the shortfall, the greater the penalty.

94. The regime would also need to address circumstances in which a participant has taken all reasonable steps to secure the required cover but is nevertheless unable to meet its obligation because of events genuinely outside its control. That may include, for example, force majeure events, unforeseen delays or failures on the part of counterparties, or other disruptions that could not reasonably have been prevented or mitigated by the participant. A penalty framework that took no account of such cases may be unduly harsh.

95. At the same time, any such qualification would need to be framed carefully. If drafted too broadly, it could undermine the obligation by allowing participants to characterise ordinary commercial risk as something beyond their control. The regime would therefore need to distinguish between events that are genuinely exceptional and those that simply reflect the kinds of risks participants should be expected to manage through prudent contracting, portfolio design and contingency planning.

96. More generally, the penalty framework should support the credibility of the scheme without making it unduly rigid or punitive. The objective is not to punish participants for its own sake. It is to ensure that the obligation creates a real commercial incentive to secure dependable winter

cover ahead of time, and that failure to do so carries consequences commensurate with the importance of the underlying reliability problem.

Table 3: Framework for long-term obligation penalty regime			
Option	**Primary lever**	**Penalty strength**	**Illustrative example**
Reputational + minimal financial penalty	Public disclosure and signalling	**Low** (nominal, subject to participant's view of reputational impact)	Reputational impact drives organisational focus but does not change future investment decisions.
Financial penalty sufficient to *tilt* investment cases (preferred)	Risk-adjusted financial incentives	**Medium** (material at the margin) shifts borderline investment cases towards financial close	Expected penalty (avoided cost) is factored into investment models and purchasing decisions. Previously marginal investments become economic.
Financial penalty sufficient to force investment cases	Regulatory compulsion via penalties	**High** (dominates investment economics, ensures investment occurs)	Repeated penalties exceed the cost of compliance, making non-investment an inferior option

Alternative approach: A generator-focused winter energy obligation

97. In developing the proposed winter energy reliability obligation, consideration was also given to whether the long-term obligation should instead be placed on generators, rather than on wholesale purchasers. This section outlines that alternative approach and invites views on it. However, this option has not been developed to the same level of detail as the wholesale purchaser model, which remains the preferred approach.

Why a generator-focused obligation could be attractive

98. A generator-focused winter energy obligation could place responsibility more directly on the parties best positioned to influence dry-year outcomes. Generators control, or are closely involved in, the investment, maintenance, fuel procurement, and operational decisions that ultimately determine how much firm winter energy can be supplied to the system under stressed conditions.

99. Placing the obligation on generators could therefore address dry-year risk more directly by focusing on the supply-side resources that are most affected by adverse hydrology and fuel constraints. It may also encourage generators to integrate firming solutions more systematically alongside intermittent generation, rather than relying on future scarcity pricing, emergency measures, or demand curtailment to manage dry-year exposure.

100. Further, investment in firm generation is inherently risky, and typically requires long-duration contracts to manage that risk. Those contracts may need to extend well beyond the specific year in which the SOSA has defined a shortfall. There is a risk that some wholesale purchasers may find it difficult to commit to a seven to ten year contracting horizon, particularly where the benefits accrue system-wide rather than to a specific customer base. In that context, a

generator-focused obligation could, in principle, provide a more robust pathway to bringing forward and sustaining firm winter resources.

Key challenges and drawbacks of a generator-focused model

101. At the same time, a generator focused obligation would raise several significant design and policy challenges that would need to be resolved.

102. First, it would be necessary to determine how the obligation should be allocated across generators with very different technologies, portfolios, and exposure to dry-year risk. Possible allocation bases include expected generation, dry-year generation, or projected dry-year shortfall. Each would create different incentives and distributional effects. Allocation based on generation volumes, for example, may poorly reflect exposure to fuel risk, while allocation based on dry-year shortfall depends heavily on modelling assumptions that may be contested.

103. Second, although a generator focused model targets the supply side more directly, it would still rely on contracting to recover costs and manage risk over time. Investment in firm generation or demand response would almost certainly require long-term revenue certainty, and the commercial effects of the obligation would ultimately need to be transmitted to consumers through contracts. This raises questions about how costs are shared, how contracting obligations are coordinated among generators, and whether the regime would lead to efficient risk allocation.

104. Third, there may be a risk that a generator centric obligation could disincentive demand-side solutions. However, the obligation on generators doesn't prevent them from seeking demand-side solutions from wholesale purchasers and procuring these via contracts.

105. For those reasons – and those set out earlier in the paper – our recommended approach is the wholesale-purchaser model described above. However, we welcome views on whether a generator-focused model would be preferable, either instead of, or alongside, the wholesale-purchaser model.

A limited point of comparison: Australia's retailer reliability obligation

106. Australia's retailer reliability obligation (RRO), implemented in 2019, is the closest readily identifiable comparator to the long-term obligation. In broad terms, it is a forecast-based ex ante mechanism under which liable entities – primarily retailers – may be required to demonstrate that they hold sufficient qualifying contracts or other cover where a forecast reliability shortfall is identified. It is therefore relevant as a point of comparison, even though it is not directed at quite the same problem as the regime proposed in this paper.

107. The Australian RRO is fundamentally a capacity adequacy mechanism, focused on ensuring that sufficient firm capacity is available to meet peak demand. It does not address energy adequacy or longer-duration supply risk in the way envisaged by the obligation proposed here. More generally, contemporary RRO-style mechanisms internationally appear to follow this same capacity-adequacy model. We are not aware of any modern scheme that directly targets energy adequacy or long-duration security of supply risks in a form that could readily be adapted to the New Zealand market.

108. Even so, the Australian experience provides some reason for caution in relation to the design and implementation of a mechanism of this kind. In particular, it suggests that forecast-based adequacy mechanisms can become complex and administratively demanding in practice. That reinforces the importance of ensuring that any New Zealand regime is kept as workable, proportionate, and targeted as possible.

109. The Australian experience also suggests that an obligation of this kind is unlikely to operate most effectively in isolation. The RRO forms part of a broader reliability toolkit, including measures intended to support contract market liquidity. That may hold a broader lesson for New Zealand: if a long-term obligation is introduced, it will likely also need to sit alongside other complementary measures, rather than be expected to solve the dry-year problem on its own.

Discussion questions

Q5.	Do you agree that a long-term obligation should be introduced to strengthen incentives to secure sufficient dependable winter cover in advance where a forecast winter energy adequacy shortfall is identified? If not, why not?
Q6.	Do you agree that the long-term obligation should be placed on large wholesale purchasers rather than on, say, generators or the market more broadly? If not, which parties should hold the obligation, and why?
Q7.	Do you agree that a de minimis threshold should apply to limit the obligation to wholesale purchasers with a material winter load? If so, is the 500 GWh threshold appropriate, and should it be measured by reference to aggregate load over the winter period?
Q8.	Do you agree with the proposed staged approach under which a warning notification would be issued five years out, a binding obligation would be issued three years out and compliance would be assessed one year out? If not, what timing or trigger approach would be preferable?
Q9.	Do you agree that any identified adequacy shortfall should be allocated among obligated wholesale purchasers by reference to their shares of expected winter demand? If not, what allocation approach would be preferable?
Q10.	What forms of cover should be eligible to meet the long-term obligation?
Q11.	How should the compliance framework be designed? In particular, what evidential standard should apply, and how should the regime address more difficult issues such as hydro treatment, attribution, portfolio treatment, shared arrangements and double counting?
Q12.	Should the regime deal with arrangements that appear compliant in advance but later fail because of counterparty failure, project delay, force majeure or similar events? If so, how?
Q13.	Should penalties for non-compliance be designed and calibrated to tilt investments to comply without overly encouraging inefficient over-procurement? Please explain your reasoning.
Q14.	What other design features, transitional arrangements, or implementation issues should be considered to ensure that the long-term obligation is workable, proportionate, cost-effective, and beneficial for consumers?

Short-term obligation: providing an in-year backstop where a near-term winter reliability risk emerges

The short-term obligation will ensure that, under emerging dry-year conditions, generators are responding quickly to ensure there is enough genuinely firm fuel cover in place to get the system through winter.

110. It is directed at a narrower possibility that, although the long-term obligation may have already operated, the position has nevertheless deteriorated to the point where an additional layer of protection is needed – and soon.

111. A short-term obligation of this kind would deliver substantial benefits. As noted earlier, the consequences of dry-year conditions can be severe, both within the electricity market itself and across the wider economy. A mechanism that reduces the risk of the system entering a stressed winter position without enough genuinely firm cover in place would help reduce the likelihood of shortages, curtailment and sharply elevated wholesale prices, while also reducing the wider disruption that can follow if dry-year conditions become acute.

112. At the same time, the attainment of those benefits will depend on careful design. The key questions concern when the trigger should be activated, what the obligated parties should be required to demonstrate once it is, what kinds of arrangements should count as sufficiently firm, how compliance should be assessed, and how penalties should be calibrated. The balance of this section sets out our recommended approach and seeks feedback on those design and implementation issues.

Summary of the short-term obligation

113. Box 2 and Figure 3 below summarise how the short-term obligation would function in practice. It illustrates the main steps, from the identification of an emerging risk through to compliance and enforcement and highlights key design considerations.

Box 2: SHORT-TERM OBLIGATION

A short-term mechanism to ensure sufficient fuel contracts (or storage) are in place where potential shortages emerge

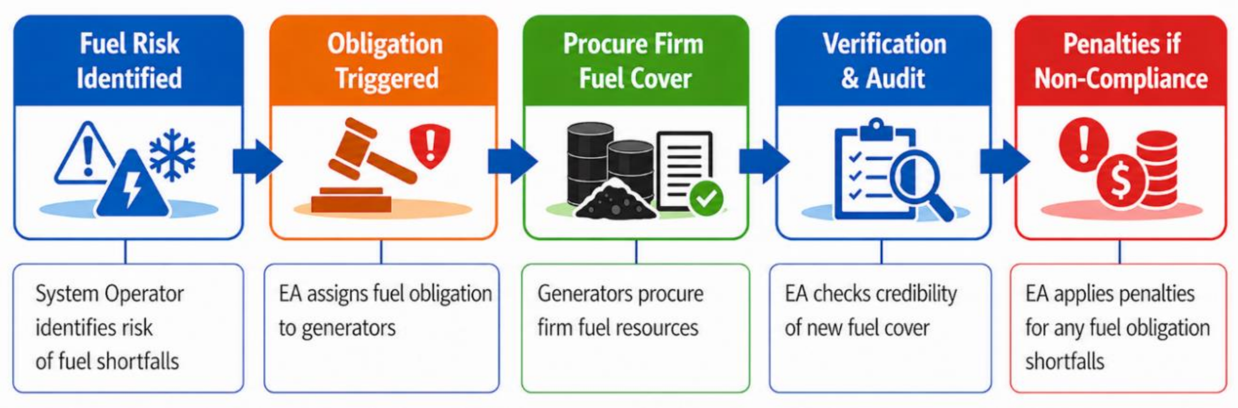
Overview

A practical, near-term reliability measure under which large generators would be required to demonstrate that they have sufficient, genuinely firm, fuel cover in place if a defined short-term winter reliability trigger is met. It is designed to provide a residual backstop where conditions deteriorate closer to winter, in addition to the operation of the longer-term obligation.

What it seeks to achieve

- Reduce the risk of winter shortages, forced curtailment and broader disruption.
- Help avoid extreme price spikes by improving confidence that firm energy will be available when needed.
- Strengthen operational resilience where hydro conditions deteriorate materially ahead of winter.

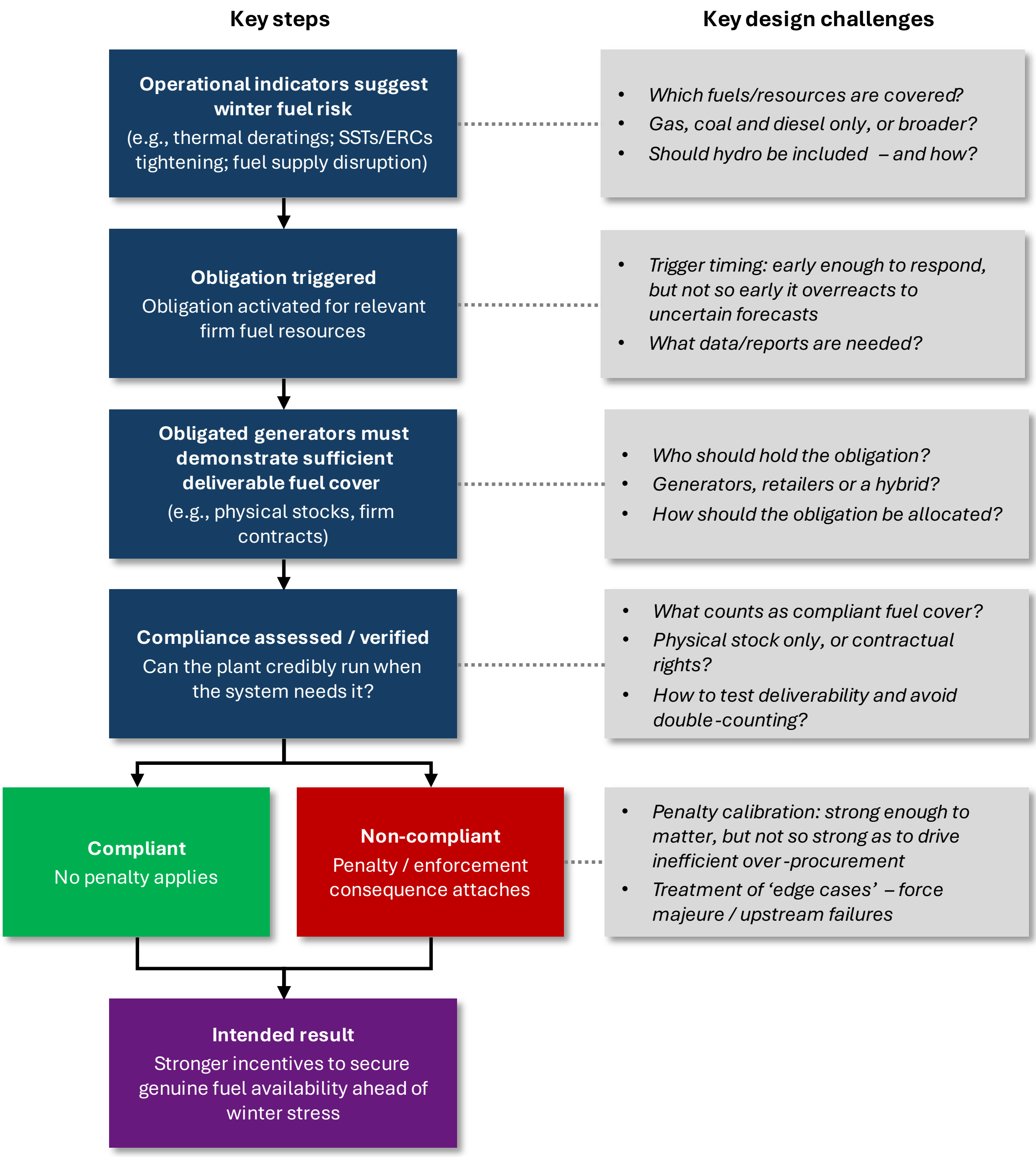
How it works (in simple terms)



Obligation features

- **Trigger:** Activated if projected hydro storage, declining at 18GWh per day, is expected to cross the Watch Curve within the next 90 days.
- **Obligated entities:** Large generators whose contribution to winter energy supply exceeds a defined threshold.
- **Obligation allocation:** Based on the winter load each generator's portfolio is expected to support, including its own retail load and relevant contractual commitments.
- **Qualifying cover:** Genuinely firm and deliverable winter energy fuel resources, which may include additional fuel for thermal generation, demand response or other arrangements capable of supporting winter supply – **Focus: any action that lowers the Watch Curve.**
- **Compliance assessment:** The Electricity Authority would assess whether each obligated generator has secured enough qualifying cover after the response period.
- **Penalty trigger:** Failure to demonstrate sufficient qualifying cover once the obligation has been triggered and the response period has elapsed.

Figure 3: Key steps and policy choices relating to the short-term obligation



Who holds the obligation? The obligation would be placed on large generators

114. The short-term obligation would be placed on generators whose contribution to annual energy supply exceeds a defined *de minimis* threshold. This differs from the proposed long-term obligation, which would sit with large wholesale purchasers. That distinction reflects the different purpose of the short-term mechanism. At this stage, the relevant question is not whether purchasers have contracted in advance for sufficient cover. It is whether, when a near-

term dry-year risk emerges, the system has enough genuinely firm long-duration firm generation to get through the winter.

115. Large generators are the participants most able to affect that near-term outcome. Their plant, fuel arrangements, storage positions, contracting arrangements and operational decisions will often determine whether the firm fuel cover the system expects to have is actually available when conditions tighten. For that reason, the short-term obligation is proposed to sit with generators that make a material contribution to annual supply.

116. As with the long-term obligation, a *de minimis* threshold should apply so that the regime is directed at generators whose actions can materially influence system outcomes. Within that constraint, the design should maximise participation and allocating responsibility proportionately across the cohort. For the short-term obligation, that threshold would be framed by reference to the contribution to annual energy supply, rather than by reference to load. On an initial basis, the threshold could be set at more than 2,500 GWh of annual expected generation, as assessed by average generation over the last five years. In practice this means the short-term obligation would apply to the four large gentailers (Contact, Genesis, Mercury and Meridian).

117. The level of the threshold is important:

- If it is set **too high**, the scheme may exclude generators whose role in winter supply is material enough that they should also bear responsibility under the mechanism.
- If it is set **too low**, the obligation may capture participants whose inclusion would add complexity without materially improving outcomes.

118. As with the longer-term obligation, the basic objective of this mechanism is to incentivise obligated participants to secure more firm fuel cover than they otherwise might, or at least to secure it sooner. That would not be costless. But, for the same reasons given earlier in relation to the long-term obligation, the rationale is that it is preferable to take those actions sooner than to leave the system exposed to the potentially much greater costs that can arise if dry-year conditions intensify as winter approaches. In that sense, the short-term obligation performs the same essential function as the long-term one, but over a much shorter time horizon and in response to a more immediate risk.

119. We welcome views on whether 2,500GWh of annual expected generation is the appropriate *de minimis* threshold for the short-term obligation. Perspectives are also sought on whether a higher or lower threshold would better balance workability, proportionality and security of supply objectives.

When would the obligation be triggered? When a defined near-term risk condition is met

120. The short-term obligation would be triggered by reference to the System Operator's assessment of near-term hydro storage risk. Its purpose is to identify the point at which conditions have deteriorated sufficiently that, despite the operation of the long-term obligation, a residual dry-year risk has emerged and a short-term response is needed.

121. Specifically, the obligation would be triggered if projected hydro storage crosses the Watch Curve within the next 90 days accounting for a hydro storage decline of 18GWh/day between 1 January and 31 July. Based on this methodology a notification curve would be derived. If hydro storage was at or below the notification curve for 21 days a formal obligation applies.

122. If these conditions are met, the System Operator would notify the Electricity Authority, which would then activate the short-term obligation.

123. In selecting the trigger, a range of possible settings were tested against historical records. The aim was to identify a trigger that would have captured years in which the system was moving into a genuinely concerning dry-year position, without also catching years that clearly did not warrant intervention. That exercise involved judgement. On balance, the 18GWh/day metric appears to provide the best fit.

124. Looking at the historical record, higher rates of decline would have caused the obligation to be triggered in too many years, including those that should not have been caught. Conversely, lower rates would have risked failing to identify years in which the system was moving into a sufficiently stressed position.

125. Figure 4, on the next page, illustrates that the selected setting would have captured 2021 (A), 2024 (B) and 2025 (D), while not being triggered in 2020, 2022 or 2023. In 2024 the notification curve is crossed later in June (C). However, this is the result of insufficient fuel in the system earlier in 2024. We considered the earlier notification (B), the subsequent obligation would increase the incentives for fuel in the system and reduce the risk of future crossings (C).

126. We therefore consider this to be an appropriate trigger but welcome feedback. It would have captured the years in which intervention appears justified, without also including years that should not reasonably have given rise to a formal obligation.

127. The System Operator would monitor the relevant indicators from the beginning of January each year, when hydro storage is generally approaching its seasonal peak, through to the end of June. If the trigger is activated, the Electricity Authority would notify the obligated generators that the short-term obligation has arisen.

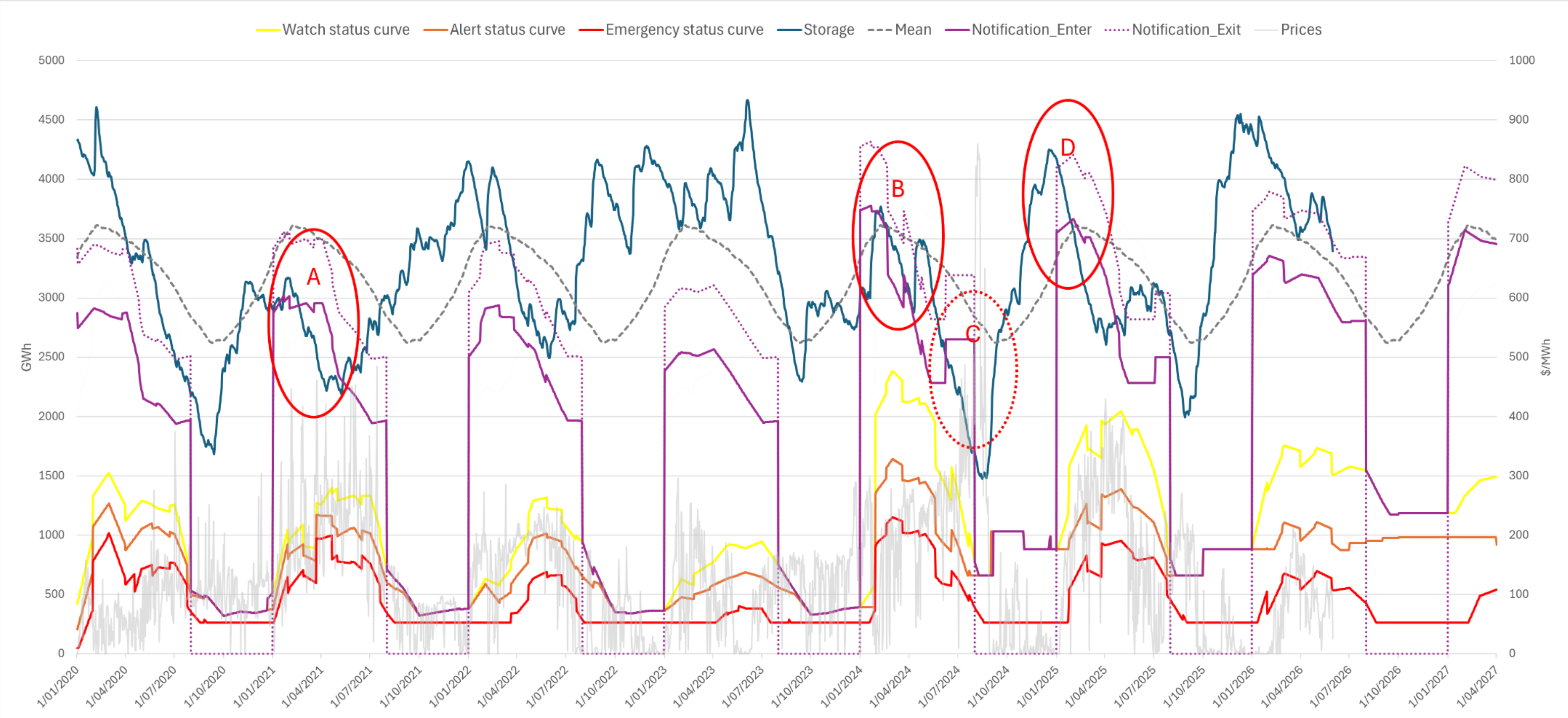
128. Like the longer-term obligation, it will be necessary that the timing of the obligation strikes a balance between ensuring that the identified shortfall is real and giving parties enough notice to respond, while maintaining confidence that there will be sufficient fuel in the system as needed. This leads into the following two-stage process:

    - **Stage One:** a three-week (21-day) 'Verification Period' to ensure information and underlying assumptions are correct before the obligation is triggered. This comprises a 7-day period to provide additional information to the System Operator and a 14-day period to re-assess the risk curves and notification curve.
    - **Stage Two:** a four-week 'Response Period' during which generators will be required to secure genuinely firm winter energy cover.

129. The first stage will involve verifying information. Obligated generators will be required to verify, and update, information provided to the System Operator for calculating the Electricity Risk Curves. Additionally, obligated generators will be required to provide the Electricity Authority information on its position (i.e., retail load and contracted commitments) and physical ability to supply (i.e., fuel, or alternative arrangements in place, to generate to meet its commitments).

130. Throughout this stage, obligated generators will be required to continuously disclose information to the Electricity Authority so that it can maintain oversight of decisions generators are making. It is intended that this information disclosure requirement will assist the Electricity Authority in its assessment of whether obligated generators fulfilled their obligations.

Figure 4: Retrospective application of short-term trigger's obligation to recent years



Source: System Operator, 4 June 2026 (provided to MBIE)

131. After this three-week period, obligated generators will be formally notified by the Electricity Authority of their obligation. Generators will then have four weeks during which to secure credible cover to meet their obligation. This could be met by directly securing more fuel (e.g., ordering more coal or a shipment of LNG), calling on demand response agreements or contracting for more long-duration firm energy (which would need to be sufficiently credible). The obligation would not be met by options that are not demonstrably reliable or credible, such as exploratory drilling campaigns aiming to find more domestic gas.

132. If conditions improve materially during that seven-week period, the obligation would fall away. The threshold for the obligation no longer applying will be set at projected hydro storage remaining above the Watch Curve for more than 120 days given an 18GWh/day decline. In this situation, the Authority would notify the obligated generators that the trigger condition no longer applies. The purpose of the mechanism is to respond to a defined residual risk, not to require action once that risk has plainly receded.

133. That possibility does give rise to a practical question. In principle, a generator may prefer not to incur additional costs immediately if there remains some prospect that the obligation will fall away. In practice, however, the scope for any such “wait and see” approach may be limited. A seven-week response window leaves little room for delay. A generator that waits risks finding that suitable arrangements are no longer available or are available only at significantly greater cost. In that sense, delay may simply replace one cost with another, whether in the form of more expensive last-minute cover, or penalties for non-compliance.

134. As with the long-term obligation, participants would not be responding in a vacuum. They would be expected to monitor the same indicators on an ongoing basis and to manage the associated risk through their own planning and operational processes. The significance of the trigger is therefore not that it reveals an entirely new problem. Rather, it marks the point at which those participants are formally required to act.

135. The System Operator is also implementing a contracted Electricity Risk Curve as part of the recent SOSFIP updates. The difference between the contracted curves and physical curves could also be used to inform the extent to which the risk curves can be reduced which could form a useful test on the extent to which the market can impact the risk curves. We consider that this should be taken into consideration as part of the detailed design as more experience is gained with the contracted and physical risk curves.

136. We welcome views on whether this is the appropriate trigger for the short-term obligation. We also invite feedback on whether the proposed notification process, three-week verification stage, four-week response stage and approach to “switching off” the obligation if conditions improve are appropriate.

Box 3: Worked example of the short-term obligation being triggered

The example below shows how this could apply during 2024. The timeline reflects the relevant periods

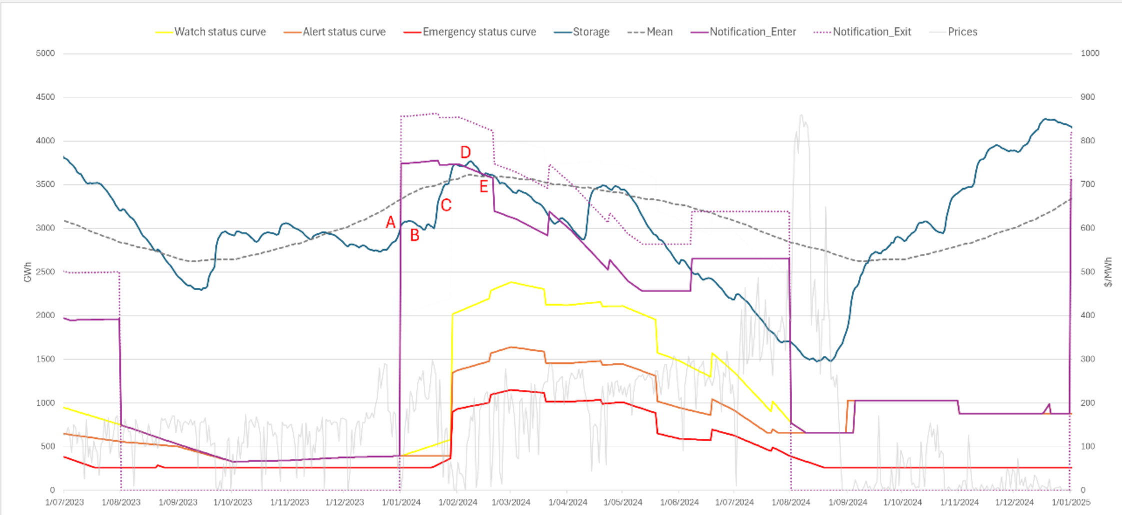
A (1-Jan-24): Controlled storage crosses the notification curve

B (8-Jan-24): Additional information provided to the System Operator to re-assess the risk curves

C (22-Jan-24): System Operator informs the Electricity Authority if storage is still below the notification curve (including new information provided by participants). Electricity Authority triggers obligation on relevant parties based if storage is below the notification curve

D Conditions need to improve materially following the Electricity Authority triggering of the obligation. This is tracked via the "notification exit" curve. In this instance storage rises above the notification curve but not the notification exit curve.

E (19-Feb-24): Parties have four weeks to respond to the Electricity Authority and confirm that sufficient firm fuel cover is available. This information would need to be submitted to the System Operator to re-assess the Electricity Risk Curves to inform the market and stakeholders how the risk has been reduced.



How would the short-term obligation be determined? Each obligated generator would be required to hold enough firm fuel cover for the winter load it is expected to support

137. If the short-term obligation is triggered, each obligated generator would be required to demonstrate that it has sufficient firm fuel cover in place to support the winter load for which it is relevantly responsible. In practical terms, that would include load served through its own retail base, where the generator is vertically integrated, as well as any additional load it is committed to support through contractual arrangements with other parties, including independent retailers.

138. The basic logic is that the obligation should follow the exposure for which the generator's portfolio is expected to provide cover. The question is not simply how much generation capacity the generator owns in the abstract. It is how much winter load its generation and related arrangements are expected to support, and whether it has enough genuinely firm fuel cover in place to do that if conditions deteriorate in the manner contemplated by the trigger.

139. For example, if a generator is expected to support, say, 5,000GWh of winter load over the relevant period – through a combination of its own retail load and contractual commitments to other parties – it would need to demonstrate qualifying cover of at least that amount. The purpose of the assessment would be to ensure that the generator can stand behind the load its portfolio is expected to serve.

140. This means the short-term obligation would not be allocated in the same way as the long-term obligation. It is not a matter of apportioning a single system-wide shortfall across all participants by reference to market share or total load. Rather, each obligated generator would be required to stand behind the winter load that its own portfolio is expected to meet. In that sense, there is no "allocation", as such.

141. However, that approach would not cover the whole system. Some generators outside the regime may still be caught short if conditions deteriorate, and the mechanism would not directly impose obligations on them. That is one consequence of using a threshold to focus the regime on generators whose contribution to winter energy supply is large enough to matter most in practice. The intention is to capture the participants capable of making the biggest difference to winter reliability, without imposing unnecessary cost and complexity by extending the obligation more broadly.

142. We welcome views on whether this is the right basis for determining the scale of each generator's obligation. We also invite submissions on whether obligations should be tied to the winter load supported by that generator's portfolio and contractual commitments, or whether some different approach would be preferable.

What must obligated parties secure? Obligated generators would be required to demonstrate sufficient genuinely firm fuel cover

143. If the short-term obligation is triggered, each obligated generator would be required to demonstrate that it has sufficient genuinely firm fuel cover in place to support the winter load for which its portfolio is expected to provide cover. The question is not simply whether the generator owns plant or holds contractual rights in the abstract. It is whether, in the circumstances that gave rise to the trigger, the generator can still point to enough genuinely firm and deliverable cover to support the obligations it is expected to meet.

144. Thermal generation would be the clearest example. But simply having thermal plant would not, by itself, be enough. The generator would also need to show that it has sufficient fuel available for that plant to run when needed. That may require, for example, ordering sufficient coal or LNG far enough in advance for it to be available in time to alleviate any looming shortage. By contrast, it could not discharge its obligation merely by pointing to fuel that it hopes to secure later (e.g., through speculative drilling or exploration). The relevant question is not whether the thermal plant exists, but whether it can in fact run.

145. Other forms of fuel security may also count where they can provide a sufficiently dependable contribution. A generator that relies on a geographically diverse portfolio of wind generation may, in some circumstances, be able to point to that as qualifying cover. But that would require judgement about what can reasonably be counted on. Wind assets cannot be assumed to generate at full output all the time, so the Electricity Authority would need to determine what level of contribution can properly be treated as sufficiently firm in the relevant circumstances.

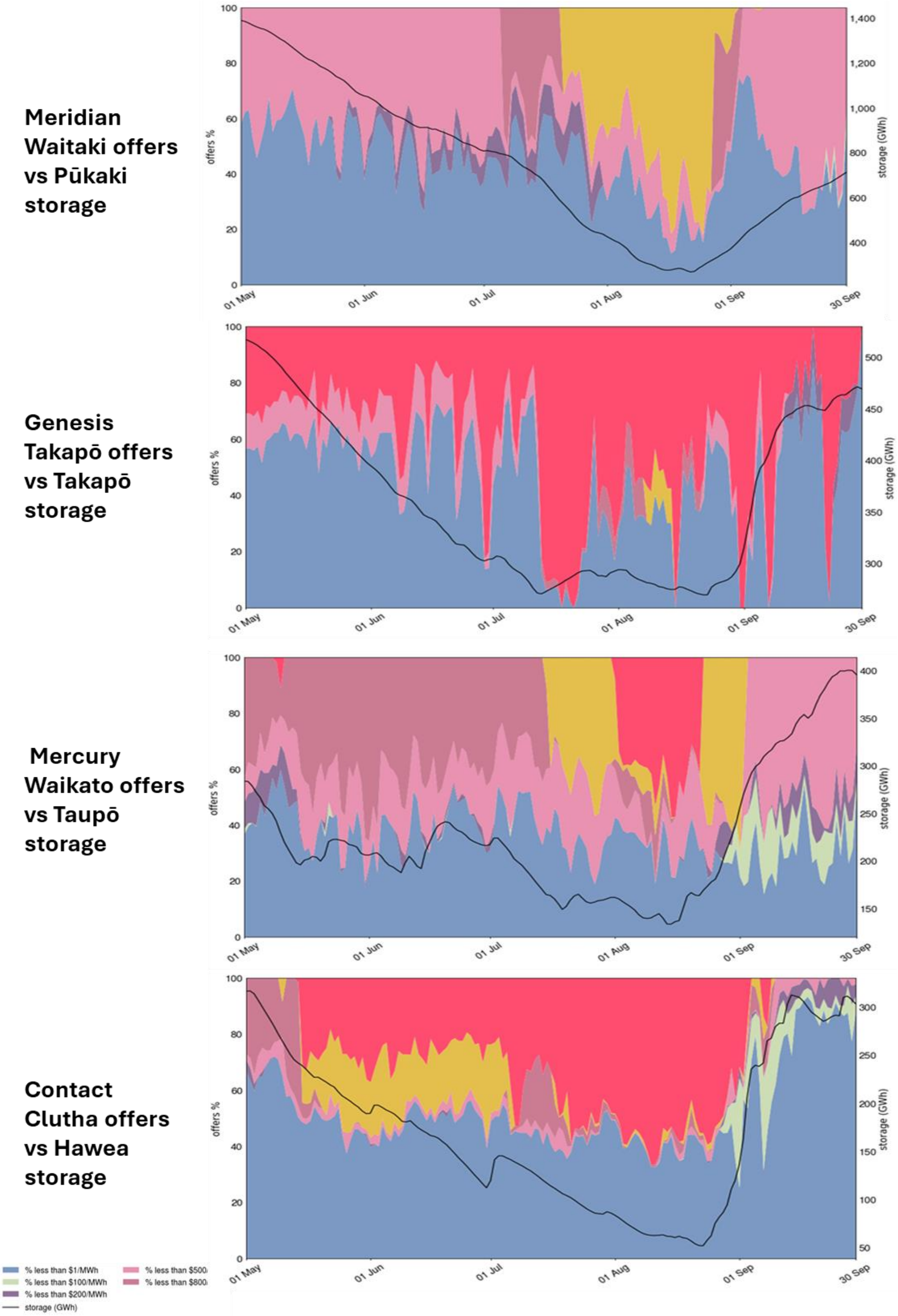
146. Demand response may also form part of the answer. Again, the existence of a contract in the abstract would not necessarily be enough. If a generator wishes to rely on demand response as part of its qualifying cover, it may need to show that the arrangement has been activated or is otherwise in a state of readiness such that it can be called upon when required. The point of the mechanism is not to catalogue theoretical options. It is to ensure that enough genuinely accessible fuel cover is in place once the trigger has been activated.

147. Once again, hydro is likely to be the most difficult case. The short-term obligation would be triggered where hydro storage is projected to fall below the Watch Curve if it continues to decline at the specified rate. In other words, it is the projected absence of stored water that prompts the obligation. That does not mean hydro should never count toward compliance, but it does mean that it probably cannot be treated in the same way as thermal plant backed by firm fuel.

148. Even when hydro storage levels are declining rapidly, a certain amount of hydro generation is expected to be dispatched. Hydro generation is not uniformly priced across all offers, so it should be expected that low-priced offers should be dispatched while higher-priced offers, those above the short-run marginal cost (SRMC) for thermal (where thermal fuel is not constrained), would not be dispatched.

149. As an example, Figure 5 below shows offers from various catchments over Winter 2024. It can be seen that, as hydro storage declines, the percentage of lower-priced offers reduces, which is an economically rational approach to conserving water. However, there is always a percentage of offers that remain lower-priced. The issue in 2024 was that there was insufficient thermal availability to displace the higher-priced offers from the dispatch order.

Figure 5: Hydro catchments over Winter 2024



150. The underlying objective of this short-term obligation is to ensure that there is sufficient alternative cover available so that hydro generation price signals illicit an appropriate response from available firm energy generators, enabling efficient hydro-storage management.

151. It will likely be necessary for the Electricity Authority to make a judgement on how much a generator should be able to rely on their expected hydro storage to meet their obligation and the optimism of generators' assumptions. That may require assumptions about likely rates of decline in particular systems or locations, given that the trigger itself is based on a national storage trajectory. Those assessments may be difficult, but they go to the purpose of the *ex ante* mechanism.

152. If the Authority did not make that judgement up front, a hydro generator might rely on existing storage even where its firmness was doubtful, and the issue would only be resolved later through penalties if the water was not in fact available. That would sit uneasily with the treatment of thermal generation. If thermal generators are expected to demonstrate that they have sufficient fuel available, hydro generators should not simply be able to assume that sufficient water will be available without similar scrutiny. Otherwise, the regime would shift away from an *ex ante* obligation to secure sufficient fuel, and toward an *ex post* sanction for failing to deliver it. That is not what is intended.

153. Similarly, it is not intended that this obligation would result in a system in which hydro storage crossing, or approaching, the Watch Curve is not permitted. There may be scenarios in which, despite reasonable action being taken early to secure additional fuel, hydro storage may remain uncomfortably close to the Watch Curve. In such scenarios, generators would need to demonstrate that additional action to lower the Watch Curve would come at too high a cost and result in poorer outcomes for consumers. The short-term obligation is not intended to incentivise action at any cost – in some cases, running hydro storage to lower levels may be the optimal outcome for consumers.

154. We welcome feedback on what forms of cover should qualify under the short-term obligation. In particular, we welcome views on how hydro should be treated, including whether, and in what circumstances, existing stored water should be capable of counting toward compliance.

How would compliance be assessed? The Electricity Authority would assess whether each generator had secured enough qualifying cover

155. The short-term obligation would need to be supported by a clear compliance assessment framework. Once the trigger has been activated and the combined seven-week response period has elapsed, the Electricity Authority would need to determine whether each obligated generator has secured sufficient qualifying cover to support the winter load for which its portfolio is expected to provide cover.

156. That assessment would need to address both the quantity of the cover said to have been secured and its degree of firmness. The question is not simply whether a generator can point to plant, contracts or other arrangements. It is whether those things can provide the support claimed for them in the circumstances that gave rise to the trigger.

157. In some cases, that exercise may be relatively direct. A generator may rely on its own portfolio of generation and demand response to meet the obligation. If it relies on its own thermal plant, the Authority may need to assess whether the plant is available to run and whether sufficient fuel has been secured for that purpose. That may involve examining whether coal or LNG has been ordered, whether it is expected to arrive in time, and whether the plant can genuinely be relied

on to provide cover during the relevant period. The existence of the plant alone would not be enough.

158. The same applies to other forms of self-supplied cover. If a generator relies on a geographically diverse portfolio of wind generation, the Authority may need to assess what level of contribution can reasonably be counted on, having regard to an appropriate capacity factor or other measure of expected output. If it relies on demand response, the Authority may need to assess whether the relevant arrangement has been activated or is otherwise in a state of sufficient readiness.

159. Once again, hydro presents the greatest challenge. As noted above, the obligation is triggered because storage is projected to fall to a level that gives rise to a materially increased dry-year risk. The Authority would therefore need to be careful not to allow a generator simply to assume a more optimistic hydrological outcome than the one that caused the obligation to be triggered. If a hydro generator sought to rely on existing stored water as fuel towards the obligation, the Authority would need to assess whether that resource is sufficiently firm in the circumstances, having regard to the expected rate of decline and the position of the relevant system. As noted above, that may require more specific judgements about local storage conditions and rates of deterioration than the nationwide trigger captures.

160. In other cases, the generator may seek to meet the obligation through cover provided by another party. For example, a hydro generator might contract for thermal firming from someone else. In that situation, the generator may be able to point to the existence of a contract. But the practical ability to perform may still depend on matters outside its direct control, including whether the counterparty's plant is available and whether sufficient fuel has been procured.

161. In those cases, the immediate question is not whether the obligated generator can prove every underlying operational fact. Often it cannot, because it is relying on others to deliver the cover. The more realistic question is what evidence the generator should be required to provide to show that the arrangement is sufficiently firm. That may include, for example, the contract itself, any warranties or undertakings given by the counterparty, any rights the generator has to receive status updates or confirmations, and any notices or certificates provided under the contract. Additionally, the generator which sold the contract will now have additional winter demand which it will need to demonstrate an ability to meet.

162. Even then, a further issue remains. The Authority may be satisfied that the obligated generator has secured a legal right to cover, while still lacking certainty as to whether the counterparty is in fact in a position to perform. One response would be to require the Authority to look further in at least some cases. But there are practical limits to how far that inquiry can sensibly go. It may not be realistic or proportionate for the Authority to conduct a detailed operational assessment of every underlying asset, fuel arrangement or commercial relationship on which a generator's declared cover depends.

163. Contractual risk allocation is relevant in that context. An obligated generator may not be able to verify every aspect of the counterparty's position directly, but it can protect itself through contract. If it has secured sufficiently strong contractual protections, including an indemnity allowing it to recover any penalty in the event of non-performance, that should create a strong incentive for the counterparty to perform. On that basis, the Authority may not need to look much further than the contract in most cases. A sufficiently robust contractual arrangement could, in most circumstances, be enough.

164. We welcome views on how the compliance framework should be designed, including what evidence should be required and how the Authority should approach more difficult questions of firmness, attribution, and reliance on third-party arrangements. In particular, we would welcome international examples of how these issues have been dealt with in other jurisdictions.

What happens if generators do not comply? Penalties would apply if obligated generators fail to put sufficient firm fuel cover in place

165. The short-term obligation would require a credible penalty framework, administered and enforced by the Electricity Authority.

166. As with the long-term obligation, this fuel obligation must have sufficient penalties attached to ensure parties comply and change their behaviour, rather than just accept a penalty. The new higher penalties that will soon be available for breaches of the Code should be relevant for serious breaches of this obligation. This could the higher of up to $10 million, or three times the commercial gain, or 10% of a company's turnover.

167. Once the trigger has been activated and the response period has expired, a generator that has failed to put sufficient qualifying fuel cover in place should face serious financial consequences. The level of those penalties would need careful calibration:

    - If set **too low**, they may simply be treated as another commercial cost and absorbed or priced in without materially affecting behaviour.
    - If set **too high**, they may drive unnecessarily expensive or inefficient responses, with those costs ultimately flowing through the market.

168. Separate from the level of any penalty is the question of form. One option would be a shortfall charge calculated by reference to the amount of qualifying cover the generator was required to have in place but did not. That would tie the penalty directly to the scale of the failure. A larger shortfall would attract a larger penalty.

169. The regime would also need to identify clearly what forms of non-compliance attract liability. The clearest case is where the generator reaches the end of the response period without having secured sufficient qualifying fuel cover. But the framework may also need to address cases in which a generator claims to have secured cover that is not, in fact, sufficiently firm, or materially overstates what a particular arrangement can reliably deliver.

170. As with the long-term obligation, the position is more difficult where a generator has taken all reasonable steps to comply, but events outside its control nevertheless prevent performance. That may include force majeure events, transport disruption, upstream supply failure, or counterparty failure that could not reasonably have been prevented or mitigated. A penalty framework that made no allowance for such cases may operate too harshly.

171. Any such allowance for such factors would, however, need to be defined with care. The short-term obligation is directed at a period in which risk has already become acute. Generators should therefore be expected to move quickly, build in contingency, and manage the ordinary commercial and operational risks that arise in securing near-term fuel cover. Any qualification should be confined to genuinely exceptional cases, rather than risks that should have been anticipated and managed.

172. The overall objective of the penalty framework is to ensure that, once the trigger has been activated, generators have an appropriately strong incentive to secure real and reliable fuel cover within the response period. It should make clear that a generator cannot simply rely on optimistic assumptions, weak arrangements, or delay once the system is already moving into difficulty.

How the short-term obligation would interact with other market developments

Relationship with the LNG import facility

The short-term obligation would sit alongside the Government's procurement of an LNG import facility. The two measures would be complementary. The short-term obligation would create a requirement to secure genuinely secure fuel cover where a near-term reliability risk emerges. The LNG facility would provide an additional, dependable means of securing fuel for gas-fired generation, which may be one form of qualifying fuel cover under the regime.

That relationship is important because LNG procurement and delivery are not expected to occur instantaneously once dry-year conditions become apparent. Fuel may need to be contracted for and scheduled in advance, taking account of shipping lead times and delivery logistics. If a generator intends to rely on LNG-backed generation to meet its short-term obligation, it would need to demonstrate that the relevant fuel and delivery arrangements are sufficiently firm to support generation when needed.

The short-term obligation would not require generators to use LNG, or any other particular fuel. It would remain technology- and fuel-neutral. But the LNG import facility may expand the practical options available to generators by making LNG-backed generation a more credible source of compliant fuel cover. That is the role the import facility is intended to play: increasing the range of credible options available to manage dry-year risk, without predetermining which option generators must use.

Relationship with the Huntly Strategic Energy Reserve

In November 2025, the Commerce Commission authorised the Huntly Strategic Energy Reserve agreement between Genesis and Contact, Meridian and Mercury. The agreement secured the continued participation of Rankine Unit 2 in the market for the next 10 years and provided greater certainty that Genesis would maintain a strategic coal reserve of 600,000 tonnes at Huntly Power Station.

The agreement supports security of supply during dry years by increasing confidence that coal-backed generation will be available during winter. It helps address risks exposed in 2024, when low hydro storage and tightening gas supply increased scrutiny on whether additional coal imports would arrive in time.

The short-term obligation would be complementary to the Huntly Strategic Energy Reserve but would not duplicate it. Huntly provides one important source of secure fuel cover. The short-term obligation would address the broader question of whether each obligated generator has sufficient qualifying fuel cover to support the winter load for which its portfolio is expected to supply.

An obligated generator may be able to rely on Huntly-related arrangements, including access to coal-backed generation, where those arrangements meet the qualifying fuel cover requirements of the regime. However, the existence of the Huntly agreement would not automatically discharge the obligation. The Authority would still need to assess whether the claimed fuel cover is sufficiently firm, properly attributed, and not double counted.

Where Huntly-related arrangements are insufficient, the generator would need to secure additional qualifying cover. That may be the case if its obligation exceeds the fuel cover available through those arrangements, or if the relevant plant or fuel is not available to support the claimed volume.

Discussion questions

Q15.	Do you support the introduction of a short-term obligation as a targeted backstop where a near-term winter reliability risk emerges despite the operation of the long-term obligation?
Q16.	Do you agree that the short-term obligation should apply to large generators whose contribution to annual energy supply exceeds a defined *de minimis* threshold? We welcome views on whether 2,500GWh of expected annual generation is the appropriate threshold.
Q17.	Do you consider the proposed trigger – projected hydro storage crossing the Watch Curve within 90 days if it declines at an assumed rate of 18GWh/day – is appropriate? If not, what alternative trigger should be considered?
Q18.	Do you agree with the proposed monitoring period, notification process, three-week response window, and approach to switching off the obligation if conditions improve? If not, what alternative process would be preferable?
Q19.	Do you agree that each obligated generator's obligation should be determined by reference to the winter load its portfolio is expected to support, including its own retail load and relevant contractual commitments? If not, what alternative basis should be used?
Q20.	What forms of firm energy fuel cover should qualify under the short-term obligation? In particular, how should hydro be treated, including whether, and in what circumstances, existing stored water should be capable of counting toward compliance?
Q21.	How should compliance be assessed? We welcome views on what evidence should be required, and how the Authority should approach questions of firmness, attribution, double counting, and reliance on third-party arrangements (including examples of how these matters are addressed in other jurisdictions).
Q22.	How should the regime deal with arrangements that appear compliant in advance but fail in practice because of upstream supply failure, transport disruption, force majeure, counterparty failure, or similar events?
Q23.	How should penalties for non-compliance be designed and calibrated so that they provide a credible incentive to secure genuine firm fuel cover without encouraging inefficient or disproportionate responses?
Q24.	What other design features, transitional arrangements, or implementation issues should be considered to ensure that the short-term obligation is workable, proportionate, cost-effective, and beneficial for consumers?

Wider options that have not been developed

173. Wider potential options have been explored by MBIE and the 2.5 Expert Advisory Group, in addition to the preferred options presented in this consultation paper.

174. These were discounted for the following high-level reasons:

- **Undermining current investment signals, which are currently working well**. In particular, the Government would not consider large structural changes which could disrupt the pace or scale of new renewable generation coming online. Both Frontier and MBIE's modelling indicates that the current pipeline of new generation is performing well and is critical for improving electricity security and affordability.
- **Introducing ongoing Crown (or a public body/entity) participation in the market.** Ministers rejected any options that they considered would require the Government to 'stand in the market'. This could include active trading, capacity-procurement role, or additional interventions that could require significant ongoing Crown funding to enter contracts.
- **Conflicting with other elements of the Energy Package**. In particular, the Government intends that its decisions to begin procurement of LNG infrastructure (Action 1.1) and remove capital constrains on the Mixed Ownership Model companies (Action 1.2) should encourage additional investments in firm generation. Any interventions which may introduce incentives to delay or re-consider these potential investments would be rejected by Ministers.

175. MBIE's initial assessment indicated that the interventions presented in the following table may have been effective at preparing the market for future dry-year risks but that they could not meet Government direction for the dry-year framework and so were deemed out-of-scope.

Table 4: Wider options that have not been developed

Option	*Approach*	Summary	Reasons this option was not developed for consultation
Capacity Market	***Change the fundamental design of the market to improve investment incentives***	Introduce a new market that pays electricity producers for being available and ready to supply power during periods of market stress. This would function in addition to the existing energy-only payments.	• Risks damaging well-functioning investment signals in the spot market. • Government intervention introduces inefficiencies and hinder market functionality • Can result in over-investment, or undelivered electricity.
Strategic Reserve Scheme		A targeted capacity mechanism. Electricity generation, or demand-response resources are kept out of the market and only used when the system is under significant stress. Administered, operated and funded separately as a 'spare tyre' mechanism to provide backup for rarely occurring events that market participants do not otherwise insure against. The Government may contract with generators / asset owners for resource storage and / or operation.	• It can be very tempting for System Operators or regulators to use strategic reserves in non-emergency situations to lower spot prices, especially when consumers bear their standing costs. • Risks damaging well-functioning investment signals in the spot market. • The scheme would require central management by a government entity in perpetuity to provide confidence it would remain in reserve. • Resources in a reserve need to be tightly quarantined from the rest of the system. They are ineffective in securing additional cover if the market perceives they could be used prematurely, meaning overall reliability is unchanged.
Public fuel reserve		Targeted capacity mechanism where the Government invests in a public fuel reserve that is only released to the market when the system is under significant stress. More targeted than a "NewCo" option that directs fuel investment and procurement decisions as it functions solely as a reserve.	• Conflicts with other elements of the Government's Energy Package. If generators consider a mechanism to de-risk investments may be considered, this may delay decisions on other generation pipeline investments. • It can be very tempting for System Operators or regulators to use strategic reserves in non-emergency situations to lower spot prices, especially when consumers bear their standing costs. • Resources in a reserve need to be tightly quarantined from the rest of the system. Ineffective in securing additional cover if the market perceives it could be used prematurely, and overall reliability is unchanged.

'De-risking investment' mechanism		A service provider, contracted by the EA, would procure long-term contracts (7 – 15 years) for firm generation and sell them back into the market where buyers would require them (1 – 3 years). This service would operate as a new ancillary service with costs recovered through industry charges (although it would be designed to break even over time). Similar schemes are used overseas, usually to target investment in renewables. For example, New South Wales' Long-Term Energy Service Agreement (LTESA) aims to incentivise investment in renewable energy generation, long-duration storage, and firming infrastructure as ageing coal-fired power stations retire. The Australian federal Capacity Investment Scheme (CIS) aimed to underwrite large-scale renewable generation and clean dispatchable capacity (storage). A replacement for the CIS, the Electricity Services Entry Mechanism (ESEM) is being developed.	• Undermines existing investment signals. • Would require element of determining amount of contracting required, risking over-procurement. • Increases market vulnerability to poor performance, market participant liquidity and fluctuating interest rates. • Could require significant additional Crown funding to establish service.
Reliability must-run contracts	***Intervene in market design to prolong the existence of generation assets / reserves***	Agreements between System Operator and generators to ensure the continued presence of critical generation plant at end-of-life status. Compensation is based on the fixed costs of generation asset maintenance and energy produced. May operate generally in the market, or under specific dispatch conditions.	• Introduces incentives to delay or re-consider other elements of the Government's Energy Package via the continued existence of end-of-life thermal generation plant. • Continued presence of end-of-life thermal generation discourages investment in new firm generation, therefore this lever could be ineffective at securing additional such plant.
Legislated minimum capacity		Legislate that dropping below a minimum reserve capacity results in a pecuniary penalty.	• Generators/reserve operators may be tempted to treat the penalty as a 'sunk cost', and drop below the minimum capacity to service their hedge portfolio. • Risks damaging well-functioning investment signals in the spot market. • Hampers the development of demand-side response to security of supply risks.

Appendix A: Further detail on New Zealand's dry-year risk and why stronger incentives are needed

This appendix provides more detailed background on New Zealand's dry-year electricity risk, how the market was expected to manage it, and why further reform is now needed.

Our electricity system is changing – more intermittent renewables, less firm thermal generation and less gas supply

A1. New Zealand's electricity system faces a distinctive dry-year risk. Our hydro lakes typically supply around 25TWh of electricity each year, or around 55 to 60 per cent of total generation. But they can store only around 4.5TWh of storage capacity at any one time. That means the system depends heavily on inflows through the year to keep enough stored water available to meet demand. In a dry year, when rainfall and/or snowmelt are below average, lake levels fall and the amount of energy available from our hydro plants is reduced. When that occurs, the question of what source can fill the resulting shortfall becomes critical.

Box 4: Understanding Capacity vs Energy Adequacy

The dry-year problem is primarily one of energy adequacy, rather than capacity adequacy. It is important to understand the distinction between these two key elements of system security:

Capacity adequacy is the ability of the electricity system to meet demand at a particular moment, especially during short periods of peak demand. This may be thought of as the size of the engine in a car, or how fast the car can go.

Energy adequacy is the ability of the system to keep meeting demand over an extended period, including during a prolonged dry spell when hydro inflows are reduced. This may be thought of as the amount of fuel in the tank.

Note: **In extreme dry years**, capacity issues can also arise as hydro plants become energy-limited and cannot sustain peak output. In analogy, the fuel level becomes so low that the engine cannot fire on all cylinders, limiting maximum speed.

A2. Hydro generation is also central to the system for another reason: once built, it is relatively cheap to run, provided water is available. Its short-run operating costs (water value derived) are generally lower than those of gas- and coal-fired plant. As a result, when hydrological conditions are favourable, hydro generation will usually be used ahead of those more expensive sources and forms a crucial part of the low-cost base of the system. In wet conditions, this helps deliver large volumes of relatively cheap electricity. But that same feature also means that, in dry conditions, the loss of hydro generation is especially significant. The system is losing a large volume of comparatively low-cost supply, increasing reliance on more expensive alternatives and placing upward pressure on electricity costs.

A3. New Zealand has also seen substantial investment in renewable generation in recent years, with ~1.8GW of installed capacity added to the system. Much of that investment has been in intermittent generation, particularly wind and solar. Those technologies have very low short-run operating costs: the wind and sun cost nothing, and once the plant has been built it is generally economical to dispatch it whenever the resource is available. That makes intermittent generation valuable and means that, when conditions are favourable, it can displace more expensive forms of generation.

A4. However, intermittent generation cannot always be relied on to be available when needed unless it is able to be firmed by another source, such as batteries or hydro. Wind output depends on wind conditions, and solar output depends on daylight and cloud cover. Those resources can therefore make an important contribution to average supply without necessarily providing reliable long-duration firm energy during extended periods of system stress. During dry-year conditions, intermittent output may not be available at the times or in the volumes needed to offset reduced hydro generation. At times, calm or cloudy conditions may also coincide with periods of tighter system conditions, further increasing energy adequacy risks.

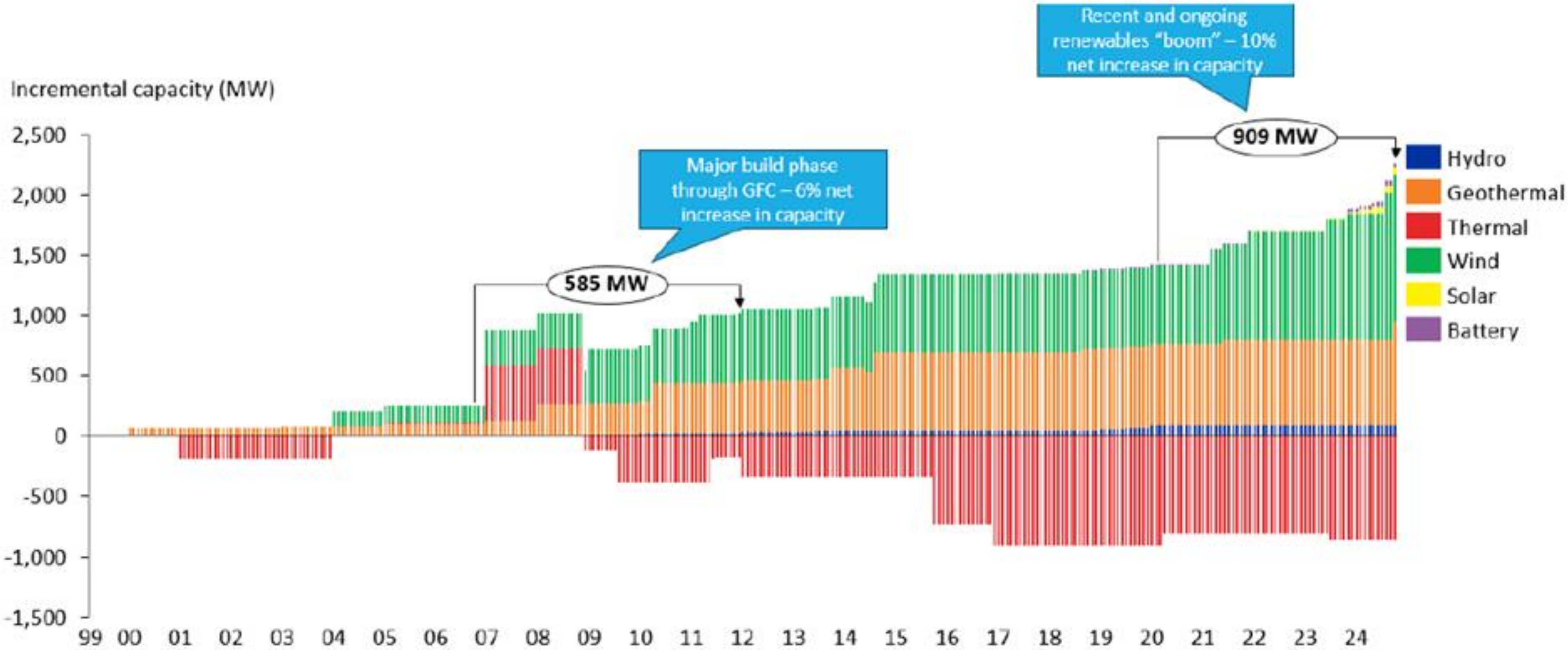
A5. These changes in the generation mix have important implications for firm thermal generation. In New Zealand's energy-only market, generators are paid for the electricity they produce, rather than for simply keeping capacity available. As more low-cost wind and solar generation is added to a system already anchored by low-cost hydro generation, higher-cost plant such as gas- and coal-fired generation are likely to run less often. That is consistent with efficient dispatch, but it also means those thermal plants have fewer opportunities to earn revenue and may find it harder to recover their fixed costs over time.

A6. That shift can be seen in the changing composition of New Zealand's generation fleet. Since 2011, around 50 per cent of thermal generation capacity (1,880MW) has retired. As Figure 6 shows, thermal plant now makes up a smaller share of installed capacity than in the past, while renewable generation has grown strongly. Although the Huntly coal-fired Rankine units remain in place, they are ageing assets, having been commissioned between 1982 and 1985, and cannot be assumed to remain available indefinitely. The net result is a system with less firm thermal generation available to support it during periods of stress.

A7. At the same time, gas availability has become a growing constraint. Gas production has fallen rapidly since 2018, and reserves have been revised down repeatedly despite substantial investment in drilling and development. This decline occurred against the backdrop of the 2018 decision to end new offshore petroleum exploration permits (since reversed), although existing permits remained in place. Forecast gas supply for 2026 is materially lower than was expected only a few years ago.

A8. This matters because gas-fired plant can support the system only if fuel is available when required. The decline in gas supply has therefore significantly worsened a longstanding dry-year risk. Although enough gas-fired generation plant may remain in the system in principle to help physically cover a dry year, there may not be enough gas that can be supplied to run gas generation plant at the level needed. That risk was exposed in 2024, as discussed below.

Figure 6: Installed capacity changes since 1999



SOURCE: CONCEPT, (2024) 'PAST AND FUTURE GENERATION PIPELINE'

Box 5: Understanding A Dry Year That Revealed System Vulnerability

In 2024, hydro inflows were low, although not close to the lowest on record. In ordinary circumstances, thermal generation would have increased to slow the decline in lake levels. However, gas-fired plant did not have sufficient fuel to run at the level required. Huntly Unit 5 – New Zealand's largest and most efficient gas-fired unit – operated at only 65 per cent of its capacity over winter, despite electricity prices being high enough that full dispatch would normally have been expected.

As a result, hydro lake levels fell faster than would normally be expected in a dry year, giving rise to genuine security-of supply concerns. Spot prices rose above $800/MWh – well above the short-run cost of coal- and gas-fired generation (around $180/MWh) and diesel plant (around $550/MWh), which would ordinarily be expected to place a cap on prices. Some industrial users paused operations; others closed permanently.

Extraordinary steps were required to maintain supply. Methanex, New Zealand's largest gas user, halted methanol production and sold gas to Genesis and Contact for electricity generation. Meridian also exercised a demand-response arrangement under which Tiwai Point aluminium smelter substantially reduced its electricity consumption.

In some respects, New Zealand was fortunate in 2024. In the previous year, which was comparatively wet, two ageing thermal units experienced significant outages. Had similar outages occurred during the dry conditions experienced in 2024, the consequences could have been much more severe. Leaving that level of risk to chance would not be prudent moving forward.

A9. Taken together, these developments have left New Zealand's electricity system in a more exposed position. In wet conditions, and when wind and solar output are strong, the system can be supplied by large volumes of relatively cheap generation. But in dry-year conditions, when hydro output falls and intermittent generation may also be limited, the system has become increasingly dependent on firm thermal generation at the very time gas supply has become less certain. The result is a system that appears well supplied in benign conditions, but is materially more vulnerable to shortages, very high prices and curtailment when conditions deteriorate. That has consequences not only for reliability, but for the affordability of electricity for households and firms, and for the wider economy.

A10. Although these concerns have already prompted a range of reforms to strengthen security of supply, those measures have not removed the need for further action. Before setting out the additional reforms proposed in this paper, it is useful to briefly summarise the market and regulatory arrangements that existed until recently, and the roles played by key parties within them. That provides important context for understanding where that earlier framework fell short, why recent changes were necessary, and why additional measures are still needed to ensure that sufficient long-duration firm energy is maintained.

The previous framework was expected to address dry-year risk purely through market incentives

A11. The previous framework for managing dry-year risk reflected a basic design choice. It relied solely on market incentives and information, rather than more direct mechanisms to secure dry-year firming. The underlying expectation was that, if dry-year risk became sufficiently acute, the prospect of very high spot prices in tight conditions and the associated commercial risks and opportunities would prompt market participants to react. That response was expected to occur in two ways:

- first, by improving the investment case for plant and other resources able to supply electricity in stressed system conditions; and
- second, by encouraging retailers and other purchasers exposed to high spot prices to enter contracts with those resources to hedge that risk.

A12. The regulatory arrangements built around the market were designed to support that process by improving visibility of risk and helping participants act on it, rather than by directing or compelling a particular response. In principle, this was intended to preserve security of supply in a way that was efficient overall and avoided imposing unnecessary costs on consumers.

Wholesale market design

A13. The starting point was the wholesale market design itself. New Zealand operates an 'energy-only' market. To be paid, generators must produce electricity – not simply have capacity available. The expectation was that, when supply became tight and spot prices rose sharply, those conditions would strengthen incentives to invest in plant and other resources able to supply electricity in stressed-system conditions. Elevated spot prices were also expected to encourage retailers and large purchasers to hedge their exposure by contracting with generation or demand-side resources capable of performing in those same conditions. In principle, the combination of contract revenue and occasional high spot earnings was expected to provide a sufficient basis for investment in the plant, fuel and demand-side capability needed to maintain reliability.

A14. Importantly, that model assumed there was no inherent need for separate payments – or other incentives – simply for keeping capacity available. Even a plant that operated only occasionally could still be commercially viable if prices were allowed to rise sufficiently during periods of system stress. The prospect of high spot-market revenues in those periods, together with contract revenue from purchasers seeking protection from those prices, was expected to allow infrequently used plant – including peaking plant and other forms of dry-year firming – to recover fixed costs and earn an adequate return over time. On that view, the energy market itself, together with the contracting it was anticipated to induce, was thought to provide sufficient reward for both day-to-day supply and resources that are needed only from time to time.

A15. In that sense, the market was expected to manage dry-year risk largely through wholesale price signals and contracting, rather than through any explicit *ex ante* obligation to hold long-duration firm energy, or any other incentive for doing so. If the prospect of tight supply conditions and high spot prices created sufficiently valuable opportunities, investors would bring forward the resources needed to capture those returns. Retailers and large purchasers, for their part, would hedge exposure to those same prices through forward contracts and other market arrangements, thereby helping to underpin the revenues needed to support investment in firming resources. The basic philosophy was that reliability would emerge, in large part, from decentralised commercial responses to market signals.

Regulatory framework and roles

A16. The regulatory framework that sits around the market reflected that same philosophy. It was relatively light-handed and directed largely at providing information, setting standards and supporting the conditions for market-led responses, rather than displacing them. In particular, it sought to improve visibility of emerging security of supply risks so that participants could respond before those risks crystallised.

A17. The Electricity Authority has a central role within that framework. Its statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. It is responsible for the principal regulatory rules under which the market operates, including the *Electricity Industry Participation Code 2010*, and for maintaining the security standards that sit within that framework. It also contracts for System Operator services. In that way, the Authority is responsible for the regulatory settings through which reliability is pursued, including the standards and Code settings that shape how dry-year risk is assessed.

Box 6: Understanding Capacity vs. Energy Adequacy New Zealand's Electricity Security Standards

Electricity is an essential service on which households, businesses, and many other critical services depend. The system therefore needs to be operated with a very high degree of reliability and security. But that does not mean it is efficient, or even desirable, to make the system immune to every conceivable contingency, e.g., highly remote possibilities that might be expected to arise only once in, say, 1,000 years. Achieving absolute reliability would require very large amounts of additional generation, transmission, storage and other backup capability, at very high cost. In many cases, those costs would far exceed the benefits.

New Zealand's electricity security standards are therefore intended to strike an efficient balance between the benefits of greater security and the cost of providing it. The aim is not to eliminate all risk, including from extremely remote events, but to define a level of security that is economically justified overall. Within that framework, market participants should have incentives to deliver that level of security efficiently: neither materially below it, which would expose consumers to undue risk, nor substantially above it, which would impose unnecessary cost.

Resource adequacy standards

New Zealand's electricity security framework includes medium-term energy and capacity adequacy standards. These indicate the level of generation and transmission capability considered sufficient to meet demand under a range of future conditions. Two types of standards are used:

Capacity adequacy

The North Island Winter Capacity Margin (NI-WCM) measures the difference between expected available capacity and peak demand during winter (April – October). It is intended to ensure that sufficient capacity is available during periods of high demand, such as cold winter evenings.

Energy adequacy

Energy adequacy standards address the risk of dry hydro conditions, when inflows to hydro lakes are low and stored energy becomes constrained. The Code specifies two such standards:

- New Zealand Winter Energy Margin (NZ-WEM): 14-16%
- South Island Winter Energy Margin (SI-WEM): 25.5-30%

These margins represent the difference between the energy expected to be available and expected winter demand.

A cost-benefit derived standard

The Electricity Authority determines these standards using an economic optimisation approach. The analysis compares:

- the cost of additional generation capacity, typically represented by new peaking plant; and
- the economic cost of electricity shortages, estimated using the Value of Lost Load (VoLL).

The efficient security standard is the point at which total system cost is minimised. At this point, the marginal cost of additional generation is equal to the marginal benefits of reducing expected energy supply shortfalls.

What this means in practice

Because the standards are based on an economic trade-off, they do not eliminate all risk of electricity shortages. Rather, they identify the level of security that is considered economically efficient for consumers, as a whole.

For example, modelling undertaken to derive the current standards indicates that:

- the capacity standard accepts that, in an average year, there may be about 22 hours when available capacity is not quite enough to meet the desired reserve or peak-demand standard; and
- the energy standard accepts that, in an average year, total electricity available may fall short of total demand by about 0.06 per cent. (approximately 100,000 households with no power for 11 days).

More severe shortages are expected to arise only rarely and would typically be managed through conservation campaigns, demand management or other emergency measures.

A18. Transpower, in its separate role as System Operator, is required under the *Electricity industry Act 2010* to (a) provide information, and short-to-medium term forecasting on all aspects of security of supply; and (b) manage supply emergencies. Those functions include scheduling and dispatch, managing supply emergencies, and publishing information and forecasts on security of supply over the short to medium term. It plays the lead role in monitoring the supply-demand outlook and producing the analytical tools on which the wider framework relies. Those tools include the annual Security of Supply Assessment (SOSA), which provides a forward-looking view of system adequacy and is intended to inform participants about emerging risks to security of supply.

A19. MBIE's role is different again. The Minister for Energy has responsibility for the primary legislation governing regulation of the electricity industry, and for the performance of the Electricity Authority as an Independent Crown Entity but does not currently have a direct operational role in managing dry-year risk. MBIE supports the Minister in those responsibilities, including by providing advice on the broader policy framework and on whether the market and regulatory settings remain fit for purpose as the generation mix changes and dry-year risk evolves.

Operation of the current regulatory framework

A20. The regulatory framework we have today (ahead of the changes signalled in Table 2 above) is heavily tilted toward a "set and forget" model. Security standards were put in place, information and monitoring arrangements were established to signal emerging risk, and market participants were then expected to respond through ordinary commercial decisions. The SOSA, security thresholds and related short-term reporting (Electricity Risk Curves and Simulated Storage Trajectories) were intended to provide progressively clearer warning signals as dry-year risk emerged. But that was all they were: warnings. The framework identified a desirable level of system adequacy, but did not include a mechanism – regulatory or otherwise – to restore the system to that level if the outlook deteriorated.

A21. Falling short of the standard therefore did not, in itself, trigger any obligation on any party to procure additional cover, secure additional fuel or invest in new firming capability. Nor did it automatically lead to regulatory intervention. The intent was for participants to interpret the risk and respond in the manner contemplated by the market design.[3]

A22. For a considerable period, that may not have appeared to be a serious weakness. The system often had sufficient long-duration firm energy in practice, so the absence of any stronger corrective mechanism did not necessarily constitute an immediate problem. But those conditions could not be assumed to persist indefinitely. Once fuel availability tightened and ageing thermal plant became less secure, the limitations of the earlier framework became harder to ignore.

There are many reasons why the existing settings may not deliver enough long-duration firm energy

A23. With the benefit of practical experience, the market-based framework did not always operate as its original design assumed. Some shortcomings in the information and contracting environment became evident as conditions tightened. Participants did not always have the tools or arrangements needed to respond effectively when conditions tightened. And even where risks were visible, incentives were not always strong enough to ensure that participants acted on them or acted soon enough. In particular, the combination of high spot-price upside and contract-based revenues that the earlier design implicitly relied upon did not consistently materialise in a way capable of supporting timely investment.

A24. More fundamentally, the framework lacked a coordinating mechanism to bring investment forward in the face of unavoidable uncertainty. With no clear focal point of the level of 'insurance' required, individual participants could rationally delay committing capital until risks crystallised, even if the delay-imposed material costs on the wider economy. Future hydro inflows, fuel availability and demand cannot be forecast with precision; this uncertainty is structural rather than temporary. Therefore, a resilient framework needs to create incentives that support investment decision ahead of need and provide greater investment certainty or desire, even when system conditions cannot be predicted with confidence.

The tenor gap

A25. A key difficulty lies in the "tenor gap" in contract markets. As noted above, the earlier market design implicitly relied not only on the prospect of high wholesale prices in tight conditions, but also on the expectation that retailers and other purchasers would enter contracts with firming resources to avoid exposure to those same prices. Those contracts were expected to complement spot-market upside and provide the revenue certainty needed to support investments. However, in practice, firming projects may require longer periods of contractual support than counterparties are willing to provide, particularly where they involve high upfront

[3] Including scarcity pricing and the Customer Compensation Scheme designed to sharpen incentives during acute operational scarcity and Official Conservation Campaigns.

capital costs but are expected to run only infrequently. Without predictable long-term income, those projects may not be financeable.

A26. MBIE-commissioned analysis has found that "for bankability, PPAs with investment grade parties of at least 10 years are required"[4] and that, for an asset developed "for security of supply purposes", the required offtake may be "at least 15 years and more likely 20-25 years".[5] The analysis also observed that "there are few examples of such assets" being developed privately without "some form of incentive mechanism" involving a fixed payment for capacity.[6]

A27. However, retailers, consumers and other counterparties are often unwilling or unable to contract for that long, because their own future demand, customer base and hedging requirements are uncertain. That reluctance is likely to be especially acute where the contract is intended to support a resource that may run only infrequently and whose value is concentrated in stressed system conditions. Transpower has observed that New Zealand's PPA market is *"relatively shallow"*[7] and is *"currently led by members of the Major Energy Users Group (MEUG) and large multinational data centres such Amazon and Microsoft)."* Beyond that, few viable counterparties exist.

A28. The result is a material risk of under-investment. Projects that may be rational from a system perspective can still fail to proceed because they cannot secure the long-dated contractual support needed to produce a bankable investment case. In that way, the tenor gap helps explain why the earlier theory did not necessarily hold. Exposure to high wholesale prices was expected to induce customers to contract with firming resources. In practice, however, the contracts the market was willing to offer were not always of sufficient duration or quality to support efficient investment. The tenor needed to finance those projects often exceeded the tenor that counterparties were willing to provide.

Revenue uncertainty and the limits of wholesale prices

A29. In the absence of long-dated contracts, investors are left to rely on the prospect of earning high wholesale revenues during relatively infrequent periods of system stress. For many dry-year firming projects, that is a weak foundation on which to base substantial upfront investment. Upfront costs are real and immediate. The corresponding revenues are uncertain in timing, amount and duration. For many projects, that asymmetry makes the business case fragile from the outset.

A30. The difficulty is not merely that wholesale revenues are uncertain in a general sense. It is that they are uncertain in precisely the ways that matter most for investment. A dry year may not occur for several years. When it does, tight conditions may not persist for long. Wholesale prices may not rise as high as expected, or other market responses may moderate them sooner than anticipated. Plant may also face fuel or operational constraints at the relevant time. Expected returns are therefore highly sensitive to a wide range of assumptions about future hydrology, demand, prices, fuel availability and the behaviour of other participants.

A31. As a result, the expected value of occasional high wholesale prices may look adequate on paper, while still being too contingent and too distant to support a real-world investment

4 MBIE commissioned analysis, *Effects of uncertainty on generation investment decisions*, p.18 (report available: **here**).

5 *Ibid, p.21.*

6 *Ibid, p.20.*

7 Transpower, *Corporate Power Purchase Agreements*, October 2023, p.30 (available: **here**).

decision. That is particularly true for long-duration dry-year firming. These are not assets that can expect frequent dispatch or steady earnings. Their value lies in being available for relatively rare but systemically important periods of stress. The commercial proposition is therefore inherently fragile.

A32. Investors may rationally prefer projects with lower upside but much more predictable cash flows. In that respect, the problem is not simply one of imperfect information or market delay. In the absence of long-duration contracts, and the revenue certainty they were expected to provide, the revenue model itself may be too uncertain to support efficient investment in the kind of insurance the system requires.

Capital and financing constraints

A33. Those problems flow directly into financing. If revenues are uncertain and long-term contracts are unavailable, debt financing becomes materially harder to obtain on acceptable terms. This is likely to be especially true for fossil-fuelled projects, which may face an additional layer of lender caution because of emissions policy, transition risk and uncertainty about future fuel use. Even where a project may have value to the system, it may still be difficult to secure financing if its future revenue profile is too volatile or too contingent. In that sense, the problem is not only whether a project is economic in theory, but whether it is financeable in practice.

Investment timing

A34. There is also a more immediate practical complication. At present, the cheapest way of providing additional long-duration firm energy may simply be to rely on the existing Huntly coal-fired Rankine units and, if necessary, to stockpile coal for use during tighter conditions. Huntly is unusual in this respect. No other existing dry-year firming resource appears able to provide comparable physical cover at similar scale by relying on already-installed plant and fuel stockpiles. That is likely to have a substantial dampening effect on incentives to invest in alternative forms of dry-year firming. So long as those units remain available, and so long as they are expected to carry a significant share of the dry-year burden, the commercial case for investing in new replacement capability becomes materially harder.

A35. The strategic reserve arrangement authorised by the Commerce Commission in November 2025 reinforces that point.[8] It secures Huntly-backed dry-year firming through to 31 December 2035, with 150MW of core capacity, a further 75MW of additional capacity in some circumstances, and an initial coal stockpile of 600kt. Transpower advised the Commission that retaining the third Rankine unit in 2026 would lower the New Zealand Watch Curve by up to 680GWh. Although the annual premium is not public, the arrangement plainly offers a comparatively low-cost way of securing a large volume of long-duration firm energy from existing plant. That further entrenches Huntly's distinctive position in the market and is likely to chill investment in competing forms of replacement firming.[9]

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8 Commerce Commission, *Determination, Genesis Energy Limited, Contact Energy Limited, Meridian Energy Limited and Mercury NZ Limited* [2025] NZCC 22, 5 November 2025 (available: **here**).

9 The Huntly arrangement does not detract from the points made above about the 'tenor gap'. Huntly is an existing asset, and its capital costs have already been sunk. The strategic reserve arrangement is therefore directed principally at securing fuel and availability from plant that already exists. A contract intended to support a new dry-year firming project would need to go further. It would need to provide sufficient revenue certainty to justify fresh capital expenditure and make the project financeable. The fact that contracting was possible in Huntly's case therefore does not show that the market can readily provide the long-duration contractual support required for new investment.

A36. However, Huntly cannot be treated as a permanent solution. Those units are ageing assets and cannot be assumed to remain available indefinitely. Their eventual exit is a not a matter of if, but when. The difficulty is that the timing of that exit remains uncertain. If investors believe Huntly may remain available for longer, they may delay committing to new projects. But if the units retire or fail sooner than expected, the system may find itself exposed before replacement capability has been developed. Replacement capacity that would require development well in advance given the large net loss associated with the loss or exit of one or more Huntly units. In that way, Huntly may both suppress new investment now and increase risk later. Any coal stockpile would then be of little practical value unless the relevant Rankine units remained available to burn it.

Fuel availability

A37. Access to fuel has been another obvious constraint. Gas-fired generation cannot provide dry-year insurance if gas is not available when it is needed. As discussed above, declining domestic gas supply has materially weakened the practical value of some existing gas-fired plant (as an always-available unit). That has created an additional obstacle for new investment: even if the prospect of elevated spot prices might, in theory, justify investment in gas-fired firming, the business case is much less compelling if there is uncertainty about whether fuel can be sourced at the relevant time and at a workable cost.

A38. The Government's procurement of an LNG import facility has an important role to play here. If delivered as planned, it may materially improve physical fuel availability and reduce one of the most immediate barriers to gas-backed dry-year firming. This policy is discussed in more detail below.

Policy and technology risk

A39. Some projects also face broader policy and technology risks. Future decarbonisation settings, the treatment of fossil fuels over time, and uncertainty about how newer firming technologies will perform or be valued can all weigh on investment decisions. Regulatory and consenting risk can add further delay and cost. These factors do not affect every project in the same way, but they can materially increase the cost of capital and reduce the commercial attractiveness of long-duration firming investment.

Information and accountability

A40. Information and institutional settings also matter. Under the earlier framework, the market relied heavily on forward-looking assessments and warning tools to identify emerging adequacy concerns and signal them to participants. Those tools were important, but they did not remove the commercial uncertainties described above. If the market was expected to invest based on those assessments, they needed to be sufficiently credible, timely and decision-useful to support contracting and financing decisions.

A41. To the extent the earlier framework did not always provide that level of clarity, that too may have weakened incentives for firms to invest in a timely and efficient manner. Some of those shortcomings are now being addressed through reforms already implemented to strengthen security-of-supply monitoring and forecasting. These measures are discussed briefly in the following section.

A42. More fundamentally, the earlier framework provided limited clarity about who was ultimately responsible for managing system-level dry-year risk. It contained no explicit forward obligation or procurement mechanism for long-duration firming. That could leave accountability diffuse and encourage participants to wait for others to move first. Warning signals might become stronger over time, but the framework had limited means of ensuring that a concrete response occurred. The following section also notes reforms intended to improve institutional clarity and strengthen the broader framework for managing dry-year risk.

The net result: action is needed to provide greater certainty that investment in long-duration firm energy will materialise

A43. Taken together, these factors meant that the earlier framework could not be relied upon to maintain sufficient dry-year firming as the system evolved. For a considerable period, adequate long-duration firm generation remained available in practice, supported in significant part by existing thermal plant and fuel. But that did not mean the framework was itself generating timely replacement investment or ensuring that long-duration firm energy would continue to be maintained as conditions changed. As the events of 2024 illustrated, once those underlying conditions became less favourable the system became exposed more quickly than had previously been anticipated.

A44. That point was not confined to the gas supply constraints that emerged in 2024. Even if those pressures had not arisen when they did, the underlying issue would still have remained. Existing thermal resources were ageing, Huntly could not be assumed to remain available indefinitely, and the system was continuing to evolve toward a generation mix with a larger share of intermittent renewable supply. The question was therefore not simply whether the earlier framework functioned tolerably under favourable conditions, but whether it was capable of preserving sufficient long-duration firm energy as those conditions changed.

A45. As foreshadowed above, significant steps have already been taken to address some of the underlying weaknesses in the earlier framework. Those measures include steps to improve fuel adequacy, strengthen information, clarify roles and provide additional tools to support the management of dry-year risk. Each of those reforms should strengthen the framework. But they do not necessarily, on their own, ensure that sufficient dry-year firming will be delivered.

A46. This paper therefore proceeds on the basis that further action is required. Its purpose is to consider what additional measures are needed to ensure that sufficient dry-year firming is delivered. Leaving the present position unchanged would expose the system to intolerable ongoing risk.

The resulting dry-year problem is significant in magnitude

A47. New Zealand lacks a substantial amount of long-duration firm energy. This is not merely a theoretical concern. As the winter of 2024 demonstrated, the system is already exposed to genuine security-of-supply risks during prolonged periods of low hydro inflows. Those risks can materialise in the form of very high prices, industrial curtailment and the need for extraordinary operational measures to keep supply and demand in balance. The problem is therefore both real and immediate.

A48. However, estimating the total amount of long-duration firm energy the system needs – and how much additional is required – is not straightforward. The appropriate quantity will evolve over time and depends on a range of uncertainties, including demand growth, the pace and composition of new generation investment, hydrological conditions and the extent to which existing firming resources can continue to be relied upon. The objective is not to eliminate all risk at any cost, but to ensure there is sufficient long-duration firm energy (or demand response) to give the market confidence that a significant dry period can be managed, without procuring so much additional cover that the costs outweigh the benefits.

A49. Even so, available estimates suggest that the amount of additional long-duration firm energy required is considerable. On one view, cover in the order of 3TWh may be appropriate to insure against a significant three-month dry period. The recent agreement between the four gentailers to maintain three coal-fired Rankine units at Huntly may help to address part of that need. However, it appears capable of providing only around half that amount at most – approximately 1.5TWh – and only for so long as those units remain operational.

A50. That is an important qualification. The three remaining Rankine units are already more than 40 years old and cannot be assumed to remain in service indefinitely. The Huntly arrangement may therefore reduce the scale of the immediate problem, but it does not solve it. Even on optimistic assumptions, a substantial amount of additional long-duration firm energy is still needed. That is why the Government has already introduced several measures to mitigate dry-year risk, and why this paper considers further measures aimed at ensuring sufficient dry-year firming is delivered.

A51. Given persistent uncertainty about future hydrology, fuel supply and demand, the central policy challenge is to create stronger, clearer incentives that coordinate investment earlier. The status quo lacked this coordination, which is why investment arrived too late and why the next phase of the reform must focus on improving the provision of long-duration firm generation ahead of need.

Glossary

Capacity market	A capacity market pays generators for being present and available to operate when needed rather than the electricity they actually produce. It is a separate market sitting alongside the energy-only market.
Code	The *Electricity Industry Participant Code 2010* is secondary legislation created and published by the Electricity Authority to regulate New Zealand's electricity industry.
Contracted curve	An ERC calculated assuming only firm contracted fuel is available for thermal generation, excluding additional fuel that could be procured. Greater than or equal to the Physical Curve.
Contract for Difference (CfD)	A long-term, two-way financial agreement between a generator and a contractual partner such as the Government, to ensure a stable strike price for electricity. It reduces price volatility by paying the difference if market prices are below the strike price, and requiring repayments if market prices are higher.
Dry-year risk	The dry-year risk is a situation of insufficient electricity supply from New Zealand's renewable-energy dominant generation base. It can be split into three parts: • *Physical*: The risk that reduced hydropower available or lower wind generation during dry or calm periods leaves insufficient firm generation capacity to reliably meet demand. • *Financial*: The difficulty in attracting and sustaining investment in long-duration backup generation resources that are only called upon infrequently, undermining the commercial viability of such resources. • *Economic*: The broader harm caused by elevated electricity and contract prices during dry years, impacting consumers, businesses, and the pace of further electrification.
Electricity Authority / EA	The electricity industry regulator, established under the *Electricity Industry Act 2010*.
Electricity Risk Curves (ERCs)	Modelled curves showing the hydro storage levels at which there is a specified probability (e.g. 1%, 4%, 10%) of running out of available controlled hydro storage within the next 12 months.
Energy-only market	A market in which generators recover their costs through revenues earned exclusively from the electricity they produce and sell (ie through the wholesale electricity market), without any additional capacity payment mechanisms.
Flexible generation	Electricity generation capacity that can rapidly start, increase, decrease or stop in response to changing demand or renewable generation.
Firm generation	Electricity generation capacity that is reliably available such that it can consistently deliver output when needed, over longer durations. Thermal plants, such as coal- or gas-fired power stations, are examples of firm generation capacity.
Frontier Review	Review of electricity market performance by Frontier Economics, June 2025.
Futures	A standardized derivative contract that is traded on an exchange (like ASX). NZ electricity futures traded on ASX settle with reference to the spot prices at two nodes: Otahuhu and Benmore.
Gentailer	A vertically integrated supplier of electricity that both generates electricity and sells electricity through a retail arm.
Hedge	Hedging is a strategy to minimize or offset potential losses from adverse price movements. In the electricity sector, the term hedge typically refers to a

	derivative, but it can also refer to ownership or control of dispatchable resources.
Industry participant	Industry participant, or participant, means a person, or a person belonging to a class of persons, identified in the Electricity Industry Act 2010 as being a participant in the electricity industry.
Intermittent generation	Electricity generation capacity that is not readily available such that it cannot guarantee output when required. Renewable sources, like wind or solar, are examples of intermittent, or non-firm, generation.
Long-duration firm energy / firming	Energy resources (including generation or demand response) that can be reliably used to meet demand over periods of days, weeks or months. These resources can be relied on during dry years or during extended calm and cloudy periods.
Marginal backup	The last energy resource that is needed to deliver an economically optimal amount of long-duration firm energy.
Marginal cost	Additional cost incurred to produce one more unit of electrical output. Marginal costs can be short-run or long-run.
MBIE	Ministry of Business, Innovation and Employment.
Option	A financial derivative giving the holder the right, but not the obligation, to buy (call) or sell (put) energy commodities such as oil, electricity and natural gas at a set strike price within specific timeframes.
Physical curves	An ERC calculated assuming all physically feasible generation and fuel supply can be utilised, including additional fuel procurement up to physical limits.
Power Purchase Agreements / PPA	Power Purchase Agreements are contracts between an energy buyer and energy producer where the producer agrees to supply electricity at an agreed price for a specified period.
Security of Supply Assessment /SOSA	Security of Supply Assessment, conducted by Transpower, analyses the balance between electricity supply and demand for the next decade.
Strike price	The predetermined price at which the holder of a derivative contract has the right to buy or sell the underlying asset.
Swaption	A financial derivative giving the holder the right, but not the obligation to enter into an underlying energy swap on a predetermined future date.
Tenor gap	The mismatch between long-term contracts needed by power generators to fund investment, and the short-term contracts preferred by energy buyers.
Transpower	The owner of New Zealand’s national grid, including the System Operator, responsible for the real-time coordination of the electricity system.
Watch curve	The Watch curve is the maximum of the one percent risk curve or the Alert curve plus the greater of the Watch adder (currently 200 GWh) or the worst-case monthly simulated storage drop.
Water value	A marginal opportunity cost of using stored hydro water to generate electricity at a given point in time, reflecting current storage levels, expected inflows, and future market conditions.
Winter energy cover	Energy resources that can provide energy that contributes towards the Winter Energy Margin (NZ-WEM) as assessed through the SOSA.

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