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Electricity Markets Policy
Building, Resources and Markets
Ministry of Business, Innovation and Employment

By email: electricitymarkets@mbie.govt.nz

A proposed reliability obligation to manage dry-year risk

Meridian appreciates the opportunity to provide feedback on the Government's consultation paper on a proposed reliability obligation to manage dry-year risk.

In Meridian's opinion:

- the consultation paper has misdiagnosed a problem;
- existing incentives to manage dry year risk are strong as evidenced by 2024 and the market has rapidly evolved since 2024;
- dry year risk is already being managed by market participants and is expected to reduce over time;
- the proposed Winter Energy Reliability Obligation (WERO) would:
    - result in a range of perverse unintended consequences, market distortions, and inefficiencies; and
    - increase the average wholesale component of prices to consumers by between $15 to $50/MWh, or up to $2 billion per annum;[1] and
- the Government must take the time to properly assess the costs and benefits of the proposal ahead of any decision to proceed, including how any LNG project and the WERO would duplicate costs to solve the same perceived problem.

Meridian's submission elaborates on each of these points, which are also supported by independent analysis from Carl Hansen of Capital Strategic Advisors (appended to this

[1] Concept Consulting *Review of proposed dry-year reliability obligation* (annual wholesale purchase cost assuming 40,000 GWh consumption in a year)

submission) and Concept Consulting (appended to the ERGANZ submission). These reports provide broader commentary on the design and likely effects of WERO, the key conclusions of which Meridian also supports.

Misdiagnosis of a problem

In Meridian's opinion the consultation paper misdiagnoses the problem it is seeking to solve by framing dry-year risk as the key issue. Dry years have been a feature of New Zealand's hydro-based electricity system since inception. The risks are well understood and managed by market participants under existing market structures and incentives. There has never been an energy shortfall in the history of the market.

The core concern in the consultation paper seems to be the periods of higher wholesale spot prices associated with dry years, as was experienced in 2024, and the desire to avoid a repeat. However, while such periods can be financially difficult for parties who have chosen not to hedge their exposure to the spot market, and for generator-retailers who are insufficiently hedged or whose hedge covers do not respond as anticipated, they do not amount to market failure and no market failure has been demonstrated in respect of 2024. On the contrary, the view of most experts is that the electricity market performed relatively well in 2024. As noted in the Electricity Authority's *Review of winter 2024*[2], the industry responded efficiently to overcome the unforeseen shortage of available gas, generation offers reflected underlying costs and supply, and generator-retailer revenues fell because of the high prices. While prices were higher for a three-month period, the physical security of supply situation was not severe. Lake levels reached their lowest point on 15 August 2024 when there was still 1,478 GWh of controlled storage in hydro lakes and the system operator was modelling the risk of energy shortage at less than one percent (i.e. there was still a greater than 99 percent likelihood that there would be no shortages at all times in 2024).

The appended independent report by Carl Hansen notes that:

> "The difficulty New Zealand has faced is not a deficiency in physical security of supply, nor a failure of the market's incentive structure. It is the sharply higher cost of maintaining security of supply in the face of a structural decline in gas, compounded by a run of adverse supply-side shocks and, importantly, by policy-induced uncertainty ..."

[2] https://www.ea.govt.nz/documents/7159/Review_of_winter_2024_jnOSQfc.pdf

The distinction between physical security concerns and spot price volatility concerns is important. The wholesale spot price is inherently volatile by design as it is the means to ensure the efficient allocation of resources in real time and to signal future investment needs, thereby supporting security of supply. Volatility only becomes a problem for those parties who choose to remain materially exposed to spot prices without adequate risk management. The appropriate response is therefore to strengthen transparency, stress-testing, and disclosure obligations, not to impose mandatory procurement obligations.

Existing incentives to manage dry year risk are strong as evidenced by 2024

The premise in the consultation paper is that generators face weak incentives to maintain security of supply. However, the available evidence contradicts this. Meridian and other hydro generators are particularly exposed to dry year risk and face strong existing incentives to manage those risks. Meridian does this by purchasing various risk management or insurance products to reduce spot exposure and help arrest the decline of lake levels in a dry year. Those options include demand response contracts with large industrial customers and options contracts with other electricity generators that can be called on when required.

The impacts of 2024 are evident in Meridian's financial results for the 2024/25 financial year showing a 32 percent fall in EBITDAF compared to the year prior, or in other words an approximate cost to Meridian of around $300 million. At the extremes, if Meridian does not prudently manage its dry year risk it could find itself incapable of generating enough energy to cover its supply contracts. In that scenario Meridian would become a net purchaser of significant volumes of energy on the spot market at a time when spot prices are elevated. To illustrate the point, Meridian's weekly load obligations are typically around 200-250GWh. If generation volumes drop significantly below this and the company is left with a net purchase of 50GWh over a week in which scarcity prices were triggered this would cost Meridian around $1 billion and would challenge the solvency of the company. Meridian and other generators naturally have very strong incentives to avoid that scenario.

As an added incentive, the existing market design also includes the Customer Compensation Scheme requiring retailers to compensate customers during any official conservation campaign (i.e. when the risk of shortages reaches 10 percent) by paying them each $12 per week. Given Meridian has over 400,000 customer connections, these weekly costs would be approximately $5 million, and market participants would collectively be paying their customers close to $30 million a week. As such, the existing market rules mean

market participants are strongly incentivised to avoid that cost by investing in or contracting for options based on long-duration firming resources.

The market has rapidly evolved since 2024

Since 2024, the electricity market has undergone a rapid evolution – further evidencing the effectiveness of existing incentives. In 2025 the industry's largest participants reached an agreement to maintain security supply in the face of rapidly declining gas availability. The Huntly Strategic Energy Reserve agreements were authorised by the Commerce Commission in November 2025 and provide for the availability of three Rankine units and a 600,000-tonne coal stockpile to manage dry year risk to 2035. In addition, uncertainty regarding the future of the New Zealand Aluminium Smelter (NZAS) was resolved on 31 May 2024, with the smelter signing a 20-year contract. Prior to that point, for most of the previous decade the smelter, which consumes about 13 percent of all electricity produced in New Zealand, was operating under relatively short-term contracts containing a 1-year exit period. This meant that at any time in the previous decade electricity demand in New Zealand could have fallen by 13 percent on 12 months' notice. Importantly, this new 20-year contract includes a commercially agreed and fully compensated demand response arrangement allowing for 185MW of smelter load to be turned down in extended periods of scarcity, further adding to the industry's portfolio of options to manage dry years and other tight supply events.

The signing of a long-term contract with NZAS was too recent to have much impact on the investment environment for winter 2024 itself but it has helped to contribute to vastly improved investment certainty for generation investors over the last couple of years. New Zealand is now seeing a period of renewable generation investment with a speed, scale, and depth that is unprecedented. Renewable generation is approaching 95 percent of total generation. Data from the Electricity Authority[3] shows that there is 45 GW of potential generation capacity in the industry pipeline. For context, total existing generation capacity is ~11 GW. Already committed and actively pursued generation developments alone will add over 3.2 GW more capacity to the system between 2025 and 2029 (an approximately 30 percent increase in total system generation capacity).

Prices are responding to these developments. In the 2025/26 financial year wholesale electricity prices averaged $77/MWh; consistent with prices observed in the period prior to

[3] https://www.ea.govt.nz/data-and-insights/charts-and-dashboards/generation-investment-pipeline/

2018 when the gas market went into decline. The ASX electricity futures market also now evidences the industry's longer-term expectation of lower prices at around the same level as the firmed levelized cost of energy for new generation.

Dry year risk is already being managed by market participants and is expected to reduce over time

As well as resulting in lower electricity prices, the evolution of the market since 2024 has efficiently managed dry year risk. The consultation paper fails to evidence its assertion that there is a potential 3TWh gap over three months in the hydro resources available to meet demand and that existing resources are not sufficient to close that gap. Meridian is firmly of the view that this figure significantly overstates the actual potential hydro energy shortfall in a dry year. Based on historical data, annual hydro *inflow* deficits have peaked at ~5TWh (~3TWh on a quarterly basis). However, this raw inflow deficit is not the same thing as the energy shortfall the system must cover. Hydro storage held in the system as deficits start to manifest means the actual maximum annual dry-year hydro *generation* deficit in a worst-case historic inflow scenario is in fact ~2.5TWh (or 1-2TWh over a three-month period).

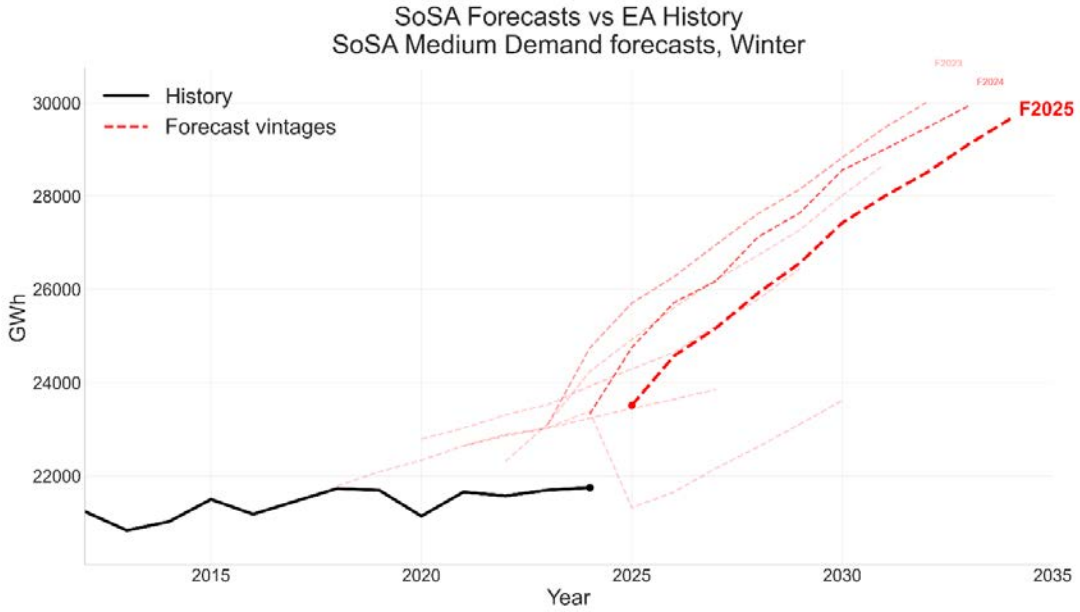
The additional energy output that can be produced under the Huntly Strategic Energy Reserve and demand response under the NZAS arrangement amounts to just over 2.2TWh over three months (comparing favourably to the worst-case 1-2TWh three-month shortfall figure seen historically) and just over 4.4TWh over six months (also comparing favourably to the worst-case 2.5TWh 12-month shortfall figure). Furthermore, the amount of renewable energy under construction means that the potential dry-year problem reduces every year as hydro storage shifts incrementally higher in the offer stack and lakes are held higher on average.

The proposal would have perverse outcomes

The proposed WERO is not needed. If implemented, it would be the most fundamental change to New Zealand's electricity market design since the marked commenced in the 1990s. It would alter existing market arrangements by shifting key elements of planning to administrative decision makers, concentrating risks that are currently diversified, and increasing risk aversion due to the inherent incentives and political exposure of central planners that control the trigger mechanisms.

Examples of the unintended distortions and inefficiencies that WERO would introduce, include:

- *Institutional incentives for administrative decision makers to err on the side of over-estimating need – leading to over-supply*. The System Operator's annual security of supply assessments demonstrate this point well, showing significant and consistent overestimation of demand, which would over-exaggerate future risks if used for the proposed long-term obligation. The resulting consistent and unnecessary over-supply would increase total system costs and increase prices overall.



Transpower may additionally experience institutional incentives to favour solutions that grow its business by increasing the Regulated Asset Base of the Grid Owner. Regardless of the measures used, or the Government organisation or regulator undertaking the assessments, the incentives will always be skewed towards risk aversion due to that organisation or regulator's accountability for dry-year outcomes under any proposal like the WERO.

- *Distorted retail competition.* Retail customers will have a higher cost to serve as each customer would increase the retailer's exposure to supply obligations and penalties. Retailers would also be incentivised to not grow beyond the size thresholds that would see them exposed to an obligation, or to reduce the size of their retail load purchases to fall under any threshold. The likely impact would be weaker retail competition and higher prices.

- *De-industrialisation, reduced industrial electrification, and higher emissions.* Any large industrial purchaser exposed to the long-term obligation would face increased costs. As with retail purchasers, the incentives would be to reduce industrial load to below the threshold or not grow beyond the threshold. As a result, the proposal would actively discourage new energy-intensive industries from entering New Zealand (for example data centres, metal production, or hydrogen production). It would also make it less appealing for the New Zealand Aluminium Smelter to continue any production above the specified energy threshold, harming security of supply if that had impacts on the availability of flexible demand response. In addition, existing industries like dairy processors would also be deterred from electrifying their process heat, exacerbating emissions reduction challenges for New Zealand.

- *Distorted competition in contract markets*. The cost of long-duration firming would likely increase, reflecting the incentives on physical resource owners to retain cover for their own exposure to the WERO and the opportunity cost of selling in advance if higher prices could be realised once buyers become compelled by the triggering of the WERO. The proposal would also disincentivise the use of contractual arrangements that do not meet the requirements of the WERO. For example, financial derivatives would be disincentivised to the extent that any contracts used to satisfy the WERO need to "shift the margins and close the shortfall assessed by the SOSA" and provide "dependable winter energy support".[4] For example, the ASX New Zealand electricity futures market is commonly used to manage dry year risk but as an exchange traded product ASX contracts cannot be easily or directly linked to physical supply. The proposal would therefore undermine the ASX as a risk management and price discovery tool and would likely disincentivise its use, reducing open interest, the number of completed trades, and liquidity.

- *Increased water values and greater utilisation of higher-cost generation.* The proposed short-term obligation would apply a lake level trigger, namely a new risk curve between 1 January and 31 July in any year showing when the 1 percent risk curve would be breached in 90 days if hydro storage were to decline at 18GWh per day from current storage levels. The proposed trigger would be extremely risk averse and would likely be commonly hit, despite any lack of security of supply concerns. Any such trigger would also incentivise hydro generators to adjust their offers to avoid triggering the obligation. Water values could be adjusted to draw

[4] Consultation paper, paragraphs 80 – 81.

water down during the compliance window at less than 18 GWh per day. This would lead to higher-priced hydro generation offers and increased use of more expensive generation, with the likely effect of higher wholesale electricity prices.

- *Workability issues.* For example, the contracts commonly executed to cover dry year risk take the form of options. Such contracts tend to involve a premium for the right to call on a contract for difference of a volume nominated by the purchaser up to an agreed maximum at an agreed strike price or subject to a call fee (for physical demand response). If a generator-retailer has an obligation to procure cover for some of the rest of the market under the long-term obligation, then it would likely use options to do so. That would likely satisfy the long-term obligation provided there was a link to physical resources. However, given the generator-retailer itself would have no need to call on the option volume to a level greater than that necessary to cover its own portfolio it would have no incentive to call on at least some of the option volume in a real-time shortage situation (and therefore the linked physical generation or demand response may not be incentivised to operate).

The proposal would significantly increase electricity prices

The WERO proposal would force industry participants to over-procure dry year insurance and would distort existing market incentives, resulting in significant inefficiencies in the retail, wholesale, and contract markets. The net effect would be increased electricity prices for consumers. Concept Consulting has estimated the proposal would increase the average wholesale component of prices to consumers by between $15 to $50/MWh, or up to $2 billion per annum.[5]

The consultation paper focuses on a perceived dry year risk "premium" in the contract market, and a belief that is somehow artificial and can be reduced at a net benefit to consumers. Contract prices such as those on the ASX electricity futures market prices reflect the market's collective probabilistic assessment of future wholesale prices across wet and dry years. That is entirely prudent, reflects actual risk, and as such describing all or part of the price as in some sense a "premium" is problematic. While it would be possible to over-insure to reduce spot prices in a dry year, there is no free lunch and the cost of that additional insurance will likely raise average prices across all years, with economy wide ramifications including the slowing of electrification and decarbonisation efforts. The

[5] Concept Consulting *Review of proposed dry-year reliability obligation* (annual wholesale purchase cost assuming 40,000 GWh consumption in a year)

consultation paper recognises that “of course, increasing reliability is not without cost.” However, no attempt is made to quantify the cost of the proposal. Instead, the paper treats it as an article of faith or as somehow self-evident that the benefits to consumers exceed the costs. Meridian queries this and suggests that given the potentially significant impacts on consumers of what is proposed, some attempt should be made to model the likely outcomes and to estimate the anticipated benefits and costs before the proposal proceeds.

The consultation paper elsewhere acknowledges that “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.”. However, Meridian notes that it is entirely imprudent to insure against an event if the cost of the insurance exceeds the cost of the insured event or if the event has already been insured against.

Next steps

In Meridian’s opinion, any policy response must recognise the evolution of the electricity market since 2024 and avoid locking in an unnecessary administrative mechanism that undermines existing market signals and significantly increases electricity prices.

At a minimum, the Government must take the time to properly assess the costs and benefits of what would be the most significant change to wholesale electricity market design since the market was established. The proposal lacks the detail needed to assess how it would operate – and the limited details provided point to significant adverse impacts. Meridian would be concerned if decisions were made to proceed with the proposal based on currently available information.

The Government should also consider the proposal against the appropriate counterfactual – including parallel measures that have been agreed but not yet implemented. The Government’s Energy Package includes procurement of an LNG import facility. According to the Government, “An LNG import facility is the fastest and most affordable way to cover the dry-year gap”. If a physical solution is being implemented to address the same perceived dry year risk, then it is not clear what additional benefits would be delivered by the WERO or anything like it. Regardless of whether the dry year problem is real, there is no point solving it twice, especially given the costs involved.

A less risky and more effective response would be to enhance the energy-only market by targeting the financial and informational issues that appear to be driving the Government's concerns. As Carl Hansen concludes:

> "The central problem the government most wants to solve — the political cost of dry-year events — is not mainly a physical problem at all. It is financial and informational. It is financial because the acute distress falls on a small number of heavily exposed industrial users, and the remedy for financial exposure is financial: securing hedge cover well in advance. It is informational because high spot prices are so easily mistaken for a failing system when they are in fact a functioning one, and because ministers are too often left without the independent, credible information they need to resist opportunistic lobbying. Addressing these two things directly would do more to restore durable confidence than any quantity-based obligation."

Measures such as enhanced stress-testing and information disclosures would more accurately target those problems than a new quantity-based obligation. If, despite the evidence to the contrary, the Government is concerned that market incentives to manage dry year risks are insufficient, it should first consider adjustments to existing regulatory tools like the customer compensation scheme, before introducing a new obligation that would fundamentally alter market design, distort incentives, and increase costs.

Please contact us if you have any queries regarding this submission.

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Appendix: Capital Strategic Advisors *Review of the Government's proposal for reliability obligations to manage dry-year risk*

CAPITAL STRATEGIC ADVISORS

Report prepared for

Meridian Energy Limited

Review of the Government's proposal for reliability obligations to manage dry-year risk

Carl Hansen

21 July 2026

About Capital Strategic Advisors (CSA)

Based in the capital city of New Zealand, CSA provides strategic policy advice to government and private sector clients. CSA has expertise in regulatory and tax policy, market and organisational design, institutional economics, pricing theory and practice, competition and infrastructure issues, and the implications of innovation and technology change for regulatory design, productivity, and economic growth.

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Key points

- The Minister of Energy is proposing new rules that would require large electricity market participants to demonstrate they have acceptable levels of cover for dry-year events. The aim is to restore confidence in electricity security of supply.
- The proposed rules would impose **short-term obligations** on Contact, Genesis, Mercury and Meridian (the large gentailers), and would apply in the months ahead of winter if hydro reservoirs are projected to fall below specified limits in the next 90 days.
- The rules would also impose **long-term obligations** on the large gentailers and NZ Aluminium Smelters (NZAS) if projections for winter energy margins for three years ahead breach a specified standard.

The problem definition is unconvincing

- **The problem has been mis-diagnosed.** The pain of recent years was caused mainly by a steep, unexpected fall in the country's natural gas supply, Tiwai and policy uncertainty, together with worldwide increases in the cost of constructing renewable generation and coal prices (since abated). It was not caused by generators failing to prepare, and it was not a failure of the market's security-of-supply arrangements.
- **The paper misinterprets the source of high hedge prices.** It attributes high hedge prices to a "dry-year scarcity premium" that a reliability obligation would strip out. The paper offers no evidence supporting this claim. Hedge prices increased over 2018-2024 primarily because the cost of firming — particularly from gas — rose, not because the market is short of cover. Forcing companies to buy more expensive backup resources would push hedge prices up, not down.
- **The paper's case rests on a "conditions have changed" refrain that does not hold up.** The consultation paper argues that things have changed enough to justify new rules — pointing to the decline in gas, a more renewable system, and greater uncertainty. But only the gas decline is a rapid structural change, and it causes a *cost* problem for electricity. It does not mean current arrangements failed: the system came through the 2024 stress with less than a one-percent risk of running short.
- **Conditions are improving.** In the ways that matter most, conditions are in fact improving, not deteriorating — the industry has already locked in a decade of extra backup cover, and the dry-year problem shrinks each year as wind, solar and geothermal generation increases. The changed circumstances point away from the heavy-handed rules the paper proposes, not toward them.

The proposal should not be progressed further

- **The proposal is likely to undermine the regulator.** The proposal fundamentally alters the Authority's role — in effect, it becomes a market participant, undermining its impartiality and independence. The rules would likely lead the Electricity Authority to make cautious, defensible judgements about the reliability of firming plant and fuel.
- **The proposal is likely to increase electricity prices.** The new rules would push companies to *buy more* backup cover, but they do nothing to make that cover *cheaper*. Their most likely effect is to raise electricity prices rather than reduce the underlying risk.

- **The short-term obligation could reduce security of supply.** It would draw the regulator into commercial and operational decisions, making it *harder* for companies to secure additional fuel when it is in short supply. It could raise prices and reduce security of supply.
- **The long-term obligation will not restore confidence.** It does not fix what is undermining confidence: the financial hit to a handful of large industrial firms (and the associated job insecurity and employment losses) arising from structural decline in the gas sector; and the mistaken belief that high spot prices necessarily signal that the risk of physical shortages has increased. That is not the case when high prices reflect jumps in the cost of the resources used to maintain shortage risks at very low levels. High prices are how the market incentivises the deployment of resources that *keep the lights on*, not a sign it is failing.
- **The proposal targets the wrong problem.** A dry year causes two kinds of harm: a physical shortage of cheap energy, and a financial hit to companies exposed to high prices. Buying more backup cover ahead of winter addresses the first, but it is not insurance against the second.
- **Wholesale electricity prices will still rise sharply every few years.** No matter how much cover is built, low rainfall will still push wholesale prices sharply higher every few years, because expensive back-up is used to conserve water when hydro lakes run low. This reality is reflected in the price of winter versus summer hedges, which continue to show a large gap.
- **Hedge cover is the key issue.** The genuine protection against spot price risk is hedging, not more physical cover. This report shows that the proposed long-term reliability obligation, if it had been in place, would not have improved outcomes in winter 2024. This is because the system operator's three-year-ahead projections for 2024 assumed that gas output would not decline materially until after 2025.

Recommendations

- **There is a better path.** The government should drop these proposals, as it has already introduced significant change to security of supply and the security of supply problem is shrinking as wind, solar and geothermal grow. If it insists on acting, it should build in independent checks, a market-based reality test, and an automatic expiry date.
- **It also needs to improve financial management of dry year risks.** Above all, it should tackle the real driver of political pressure directly — by encouraging industrial consumers to better manage their price risk and by giving ministers and the public timely and credible information so they are not swayed by self-interested lobbying.

Conclusion

- In short, the proposal is a well-intentioned response to the stresses that occurred over winter 2024, but it is the wrong intervention, is likely to raise prices, and risks making security of supply worse rather than better.

1 Introduction

1. The Minister of Energy is proposing to introduce short- and long-term obligations on large market participants in an effort to restore confidence in future security of supply. The proposal is contained in a consultation paper entitled *A proposed reliability obligation to manage dry-year risk* (consultation paper), released on 9 June 2026.[1]

2. The consultation paper explains that important steps have been taken to reduce security of supply risks, including measures to improve fuel adequacy, strengthen information, clarify roles and provide additional tools. Nevertheless, it claims further action is required as those reforms may not ensure that enough long-duration firm energy will be delivered as the system continues to change.

3. The consultation paper emphasises that consumers have lost confidence in current security of supply arrangements, indicating this is due to the impact of winter 2024 on industrial consumers, and the associated impact on regional investment and jobs, and on the economy generally. However, these effects are mostly occurring due to the unexpected decline in gas sector output. The strain surfaces during dry-year events, but its source is the structural gas shortfall, not security of supply arrangements.

4. Of course, security of supply has not been managed perfectly, but that is an unrealistic expectation. The relevant comparator is whether current arrangements work better than the feasible alternatives. On the surface, the government's proposal appears sensible, but it carries serious risks that the consultation paper does not address. These relate to poor information and incentives.

5. Although the paper focuses primarily on incentive problems with current arrangements, it largely ignores the incentive problems with the short- and long-term obligations, reflecting a nirvana mindset about regulators and government. It provides surprisingly little evidence in support of its claims and does not consider unintended consequences or the broader implications for the role of the regulator. There is quite a disconnect between the rhetoric for stronger assurance about security of supply versus the proposed method for achieving it. These deficiencies led me to realise a clear economic framework needs to be laid out, based on decision-making under uncertainty.

6. This report evaluates the analysis and proposal in the consultation paper within a framework that incorporates 'public choice' economics and decision-making under uncertainty. The public choice aspect focuses on the incentives on government agencies and politicians to make sustainable decisions. The uncertainty aspect caters for situations when governments prefer proactive/aggressive policy choices over cautious/gradualist ones. Section 2 summarises this framework.

7. Section 3 discusses deficiencies in the assessment of current arrangements, section 4 identifies problems with the proposal and section 5 recommends measures to address them. Concluding comments are presented in section 6.

[1] https://www.mbie.govt.nz/have-your-say/a-proposed-reliability-obligation-to-manage-dry-year-risk.

2 A framework for regulation and policymaking under uncertainty

8. The consultation paper claims intervention is warranted to provide assurance that security of supply will reach acceptable levels in future. However, it does not analyse the proposal within a realistic regulatory and policymaking framework, omitting several unintended consequences and important questions. The framework in this report is summarised here and elaborated in Appendix 1.

2.1 Risk management versus prudential assurance

9. Economics distinguishes *risk*, where probabilities can be assigned to outcomes, from *deep uncertainty*, where they cannot. Two responses to handling uncertainty follow. One is the *risk management approach*, which minimises expected cost by weighting all outcomes — including extreme ones — by their probability, with no conservative bias.

10. The other approach is *prudential assurance*, which seeks to avoid large losses (because of concerns the losses are irreversible or destabilising) and accepts higher average costs to do so. Prudential approaches are common in the private sector, not just in government.

11. It is also important to distinguish between prudential assurance (guarding against an event) and insurance (being financially protected when it strikes). Conflating these terms muddies policymaking. Both approaches involve incurring upfront costs for a later pay-off, but they are categorically different: insurance pays out when the worst happens, whereas prudential assurance tries to make the worst less likely or less severe.

12. The consultation paper likens its proposal to insurance (refer para 41),[2] giving the unfortunate impression that it will largely eliminate financial volatility for wholesale market purchasers. That is very unlikely. Improving financial protection against dry-year events is essential, and more important than adopting a prudential assurance approach.

2.2 Why policymakers prefer prudential approaches

13. In this report, *policymakers* refers to ministers and their ministries advising them. Ministers are supposed to be politically driven, whereas independent regulators are supposed to ignore electoral considerations.

14. Under *public choice* economics, regulators and policymakers weigh their own interests alongside society's. Ministers can suffer acute political costs when large adverse events occur, so they typically prefer prudential assurance over risk management. They also favour financial protection where adverse outcomes cannot be avoided.

15. Sharp, physical shortages and prolonged price rises for essentials can generate large political costs. In workably competitive markets, there are almost always some firms struggling for commercial viability, so when price shocks occur, they can be pushed

[2] All paragraph numbers in parentheses are references to paragraphs in the consultation paper.

into financial distress. The political impact can be particularly significant when they are large employers nationally or regionally.

16. Independent regulators are statutorily required to ignore electoral considerations. They are typically better equipped with data, so they tend toward a risk management approach. However,the threat that serious failures pose to an agency's standing pulls them toward a prudential-lite approach.

17. From an economic efficiency perspective, the ideal is to adopt financial protection policies and use risk management to minimise expected costs. If the financial aspect is well designed, it tends to reduce political pressure for overly conservative risk management.

2.3 Real-world incentives and constraints

18. In practice, regulators and policymakers act on imperfect information about the effectiveness of their own interventions, and they face incentives that pull against the benevolent ideal.[3] Three features are especially relevant for the proposal.

Asymmetric information

19. Firms know far more about their costs, technology and conduct than any regulator, and they know it and act on it.[4] This makes accurate regulation difficult, and it carries a corollary the consultation paper overlooks: observing that firms are not making the best of a situation is no basis for intervention. Firms optimise imperfectly, but so do regulators.

Competing incentives

20. Policymakers must assemble support from voters with divergent interests, which can lead them to claim a strong prudential stance while implementing something lesser.[5] The same pressures reward interventions whose political attractiveness exceed their economic effectiveness. This encourages policymakers to adopt "transformative" one-off solutions that are easy to announce and claim credit for, but they concentrate the system's exposure in a *single point of failure*, undercutting the very assurance they are meant to provide.

Government as a source of uncertainty

21. When past policy becomes the dominant risk facing long-lived, irreversible investments, previously credible policies cease to be credible.[6] It is then not enough for the current government to disown its predecessor's approach: investors discount the risk that a future administration reverts to it, the more so where the harmful policy served a powerful constituency.

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[3] The benevolent ideal is when regulators and policymakers ignore any self-interest they have and make decisions purely in the interests of society.

[4] Refer Laffont & Tirole (1993, chs 1-2).

[5] Needing to attract support from multiple voter types (multiple principals) creates a common agency problem for the policymaker (the agent). The optimal solution in common agency situations is for the agent to provide a mixed or compromise solution that no one is entirely happy with (Dixit, 1998).

[6] Frontier Economics (2025) covered this problem in some detail regarding the electricity sector.

22. Where non-intervention is no longer credible, the government must act — and the intervention must be durable across changes of administration, or it will not be believed and so will not work.

Ratcheting

23. Finally, prudential regimes are prone to tightening over time. Because no regime can eliminate supply-side shocks, adverse outcomes are read not as bad luck but as evidence of lax process, prompting more prescription, more monitoring and tighter control. Protection from the largest losses breeds diminishing tolerance for smaller ones, so the tightening rarely stops of its own accord. The proposal should be judged not only on its first turn but on where the sequence it sets in motion is likely to end.

3 Deficiencies in the assessment of current arrangements

24. The case for intervention in the consultation paper rests almost entirely on a single proposition: that the current arrangements have failed to deliver adequate long-duration firm energy, and that this failure justifies imposing new obligations on the largest market participants.

25. This section evaluates that proposition. Drawing on the framework set out in section 2, it argues the paper has mis-diagnosed the problem. The difficulty New Zealand has faced is not a deficiency in *physical* security of supply, nor a failure of the market's incentive structure. It is the sharply higher *cost* of maintaining security of supply in the face of a structural decline in gas, compounded by a run of adverse supply-side shocks and, importantly, by policy-induced uncertainty that the paper barely acknowledges.

26. The distinction matters because it determines the appropriate policy response. A physical-adequacy problem invites the prudential-assurance interventions the paper proposes: obligations, penalties and centrally specified reliability standards. A cost-and-uncertainty problem invites something quite different: measures to reduce policy risk, to deepen hedge markets, and to support the firms and consumers exposed to price volatility. The consultation paper reaches for the first toolkit while the evidence points to the second.

27. The analysis proceeds in five parts. Section 3.1 characterises the current regime as a decentralised risk-management approach, and section 3.2 identifies key elements the paper understates, notably the financial incentives operating on gentailers and the administrative incentives already embedded in the regime. Section 3.3 argues the paper misinterprets the reasons for high hedge prices and section 3.4 assesses the paper's treatment of the evidence. Section 3.5 addresses policy credibility and durability issues.

3.1 The current regime is a decentralised risk-management approach

28. Applying the taxonomy of section 2.1, the current arrangements are best characterised as a *decentralised risk-management regime*. Individual firms choose their own risk tolerance and invest in firming resources up to the point where the expected cost of additional cover equals the expected loss from being short.

29. Decisions are based on expected cost, not on the avoidance of any specified loss at any cost — the hallmark of a risk-management, as opposed to a prudential-

assurance, approach. There are prudential elements at the margin (most boards require management to hold enough cover to avoid breaching financing covenants), but the organising logic is expected-cost minimisation, applied firm by firm.

30. Two features of the regime deserve emphasis. First, the decentralised investment decision is overlaid with *central monitoring*: the System Operator determines the components of winter supply and demand that enter the Winter Energy Margin (WEM), and the Security and Reliability Council and the Electricity Authority monitor those margins against published security standards. The regime is therefore not the laissez-faire arrangement the paper implies.

31. Second, resource-deployment decisions are themselves the product of sophisticated risk management — hydro operators use optimisation tools to value stored water and to set offer prices that trade off the risk of spill against the risk of shortage. These are not the tools of an incentive-poor market.

32. The proposal, by contrast, is a *centralised prudential-assurance regime*. Central direction arises because the Authority would specify the obligations that large participants must meet to avoid penalties; the prudential character arises from the expectation that officials adopt conservative reliability assessments and more proactively oversee procurement of firming. This has fundamental implications for the way the electricity market is regulated and operated (refer section 4).

3.2 The paper understates key elements of current arrangements

33. The consultation paper's description of how security of supply arrangements work is incomplete in ways that matter for its analysis.

The paper does not explain how uncertainty is handled in the SOSA — and understates the bias in its inputs

34. The context for security of supply is one of deep uncertainty. The system operator produces a base-case WEM projection resting on assumptions about demand growth, plant and fuel availability, the timing of new generation and operational constraints. It then produces alternative projections to show the sensitivity to key assumptions. No probabilities are assigned to those alternatives. The paper does not explain this, yet it is crucial to understanding the limitations of the proposal.

35. This omission becomes material when the paper relies on the draft 2026 Security of Supply Assessment (SOSA) to assert a shortfall, stating that "in practice, the market has not delivered enough certainty" that firm generation will be delivered (para 8). The draft SOSA is not a neutral instrument. It includes any step-up in demand with more than a 10% probability of occurring but counts new generation only where the probability exceeds 50% — an asymmetric treatment that mechanically inflates the projected gap. It also assumes general demand growth despite the absence of such growth over the past decade.

36. A shortfall constructed on generous demand-side assumptions and stringent supply-side ones is an artefact of methodology, not a finding about the market. This is the conservatism problem anticipated in section 2.2. Despite the system operator's tendency for conservative judgements (eg over-forecasting demand growth year-after-year), current arrangements have produced healthy winter energy margins (when using actual demand growth).

The paper does not acknowledge that current arrangements already impose administrative incentives

37. The paper's recurring claim that "information alone is insufficient" (para 49) — feeds a false narrative that the current approach relies solely on market-driven incentives and contains no administrative penalties. It does. Official Conservation Campaigns (OCCs) can be invoked when hydro storage reaches the 10% Emergency Curve, at which point electricity retailers are required by the Electricity Authority to pay compensation to residential consumers.

38. Characterising the status quo as "information only" understates the instruments already available. The relevant question is not whether to add administrative incentives — they exist — but whether the specific new instruments proposed improve on those already in place.

3.3 The paper misinterprets the reasons for high hedge prices

39. A central plank of the consultation paper's case for the reliability obligation is that the risk of supply shortages and unmet demand has embedded an elevated risk premium in hedge prices, so that consumers pay a "dry-year premium" year after year even in normal conditions (para 6). The paper argues that a reliability obligation, by reducing the likelihood and severity of scarcity, would reduce that premium and place downward pressure on prices (para 35).

40. In practice, the dry-year risk premium arises from several sources. Among them are uncertainty about the future fuel costs of firming plant, uncertainty about the run-time over which that plant can seek to recover its fixed costs, and uncertainty about what price it will receive when it runs. These risks are in addition to the risk of physical supply shortages and unmet demand.

41. The consultation paper implies the latter component is material and that a reliability obligation would materially reduce it. Before discussing this further, it is important to consider other drivers of hedge prices.

Fuel and equipment costs have been the major drivers of hedge prices

42. Hedge prices have been elevated and volatile since mid-2018, primarily due to changes in the cost of the fuels and resources that set the marginal price of electricity, and only secondarily any premium attributable to scarcity risk. Between 2019 and 2024 the price of gas rose sharply as domestic output fell away.

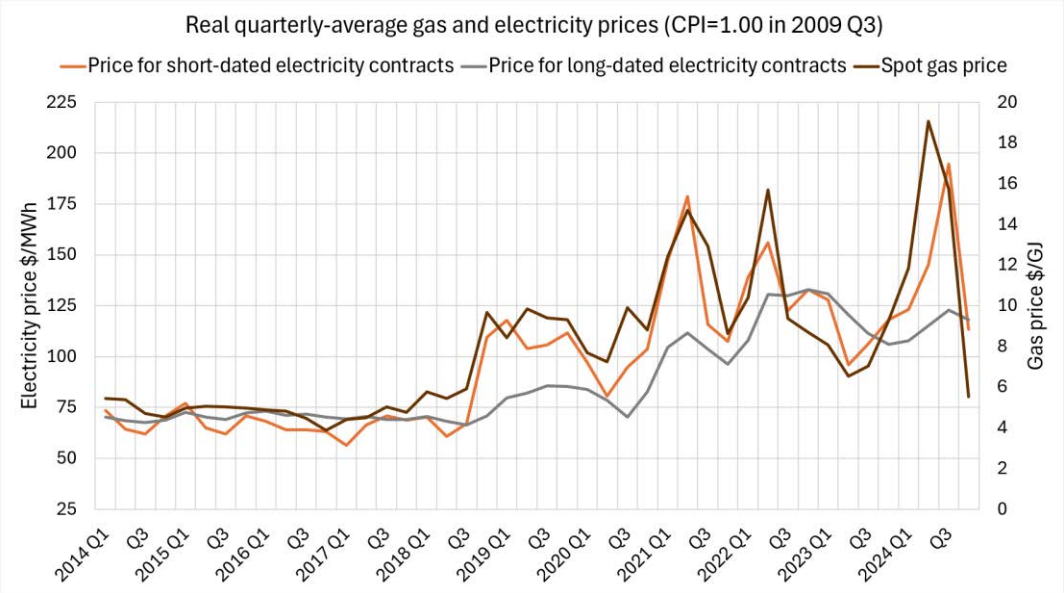
43. Figure 1 (next page) shows a strong correlation between New Zealand spot gas prices and prices for short-dated electricity contracts. Since the middle of 2018 short-dated hedge prices have exhibited large swings aligned with swings in gas prices, and the long-dated prices have increased accordingly. Short-dated prices respond to prevailing fuel costs and expected spot outcomes over the coming year; long-dated prices respond to expectations of how persistent those cost pressures will prove.

44. Further, international coal prices climbed sharply following the disruption to Australian–Chinese trade; and the global prices of wind turbines, solar panels and

batteries increased markedly in the wake of the war in Ukraine and the associated tightening of supply chains and financing costs.[7]

45. These were shortages in the fuel and equipment markets, not in the electricity market. From the perspective of the electricity market, they are cost increases — increases in the short-run marginal cost (SRMC) of firming generation and in the long-run marginal cost (LRMC) of new capacity. Both pass through to hedge prices as a matter of course.

Figure 1: Spot gas prices are highly correlated with short-dated hedge prices



46. The high correlation between hedge prices and fuel and input costs is consistent with forward pricing theory. Coulon (2009) and Carmona, Coulon and Schwarz (2012) derive electricity forward prices as a function of the forward prices of the underlying fuels and the shape of the generation supply stack. Their empirical work confirms that fuel forward prices are a first-order determinant of electricity forward prices in overseas markets.

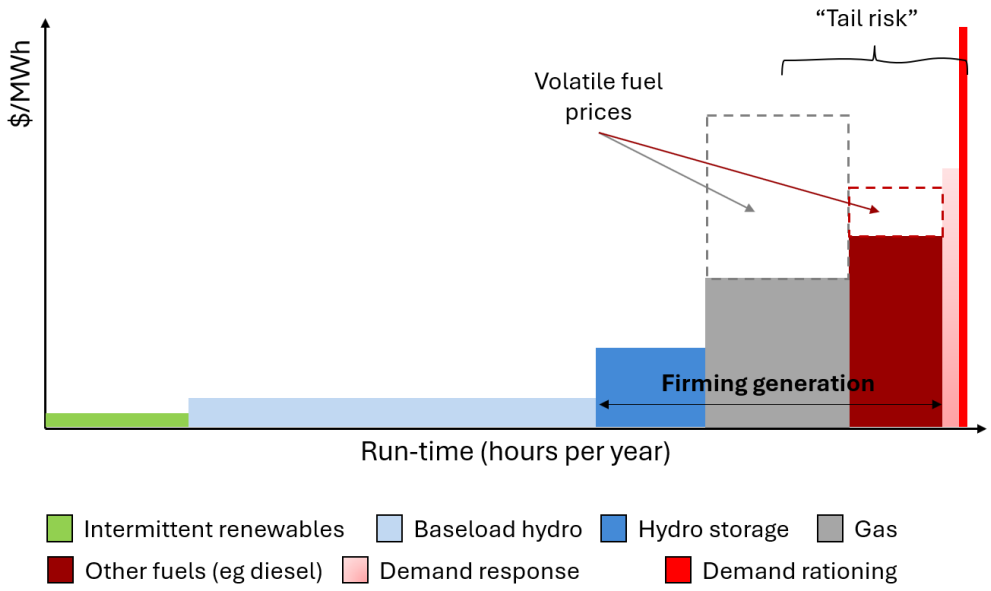
47. To illustrate their analysis, Figure 2 presents a stylised supply stack based on the short-run marginal cost of four categories of generation and two categories of demand curtailment.[8] One type of curtailment is called “demand response,” which captures demand reductions due to commercial arrangements with electricity retailers. The other type is “demand rationing” which occurs when the system operator requires rolling blackouts from consumers.

[7] Indonesian coal prices rose over 2021–2023 following China’s late-2020 ban on Australian coal; Russia’s invasion of Ukraine (February 2022), the United States Inflation Reduction Act (from August 2022) and higher discount rates lifted the levelised cost of new renewable plant, with international prices for solar panels, wind turbines and batteries up by roughly 30–40 per cent in real terms in 2023 relative to 2021. Refer Hansen (2025) for source references.

[8] For brevity, the figure omits geothermal and coal-fired generation and demand reductions arising from firms reducing demand due to commercial viability issues. It also ignores distinctions between shoulder and peaker plants. For long-duration firming in New Zealand, coal operates similarly to combined cycle gas turbines (CCGTs) and geothermal is baseload. None of these simplifications affect the argument.

48. Broadly speaking, each generation resource is dispatched when all lower-cost resources have been dispatched. The spot price in a trading period equals the price offered by the dispatched resource with the highest offer price (this is called marginal-cost pricing). The chart illustrates volatile fuel prices, which can result in situations where generation is more expensive for gentailers than activating demand response arrangements with their customers.

Figure 2: Stylised supply stack based on short-run marginal cost (SRMC)



49. Higher fuel prices lead to higher spot electricity prices. The impact on average spot electricity prices, for example over winter, depends on how reliant generators are on thermal fuel over that period.[9] The forces of arbitrage mean that hedge prices will generally reflect expectations about spot prices. The upshot is that expectations about fuel prices drive hedge prices.

There are multiple dry-year risk premia, not just the scarcity risk premium

50. The above discussion considered changes in the level of fuel prices. It follows that volatile fuel prices lead to volatile spot electricity prices. Increased uncertainty about future fuel prices can lead to a fuel-price risk-premium becoming embedded in hedge prices.[10]

51. Another dry-year risk premium arises from uncertainty that thermal-based firming plants have regarding their chances of earning a margin on their fuel costs sufficient to cover their fixed costs. Reverting to Figure 2 above, when intermittent renewable

[9] Coal and diesel prices are set internationally, so the direction is one way (from fuel prices to electricity prices). The feedback loop runs in both directions for gas, as dry-year episodes mean the electricity system increases its demand for domestic gas, pushing up spot gas prices (sometimes sharply) which increases spot electricity prices.

[10] Bessembinder & Lemmon (2002) show that a forward premium (the wedge between the forward price and the expected spot price) varies with the skewness of the distribution of spot prices and the risk preferences of market participants. This article takes the distribution of spot prices as given, whereas the Coulon (2009) and Carmona et al (2012) focus on the factors driving the distribution of spot prices.

generation is installed, it crowds out every resource to its right; if pumped-hydro storage enters, it does the same.[11] A thermal generator therefore faces the prospect that its run-time will be crowded out by growth in renewables (wind, solar, geothermal and hydro) and the installation of batteries.

52. In addition, renewables growth may reduce the average spot price thermal generators receive when they run, called their generation-weighted average price (GWAP). Or a future government may cap those prices or restrict thermal generation for climate policy reasons. Combined, these factors create a dry-year risk premium through the uncertainty they create for the generator's revenue and return on investment (ROI).

53. Figure 3 (next page) illustrates the suite of cost and risk factors affecting hedge prices. The consultation paper focuses on the scarcity risk-premium and disregards the others.[12] This is problematic because the other risk premia may increase if the proposal increases reliance on thermal sources of firming (exacerbating their SRMC risks) or "forces" gentailers to secure firming with high fixed-costs per operating hour (exacerbating their ROI risks). We return to these issues when reviewing the proposal in section 4.

In summary

54. The distinction between cost increases and a scarcity premium, and between the scarcity premium and other dry-year premia, are not pedantic ones. They are decisive for the policy that follows. If the expected cost of firming is the predominant driver of hedge prices, then compelling the procurement of more expensive firming raises the average cost of serving load, putting upward pressure on hedge prices, not downward. Upward pressure also occurs if the fuel and ROI premia dominate the scarcity premium.

55. In my view, the consultation paper reaches the opposite conclusion because it has misattributed a cost problem to a physical risk problem. The appropriate policy response to a cost problem is to reduce the cost of firming resources; the response the paper proposes would increase it.

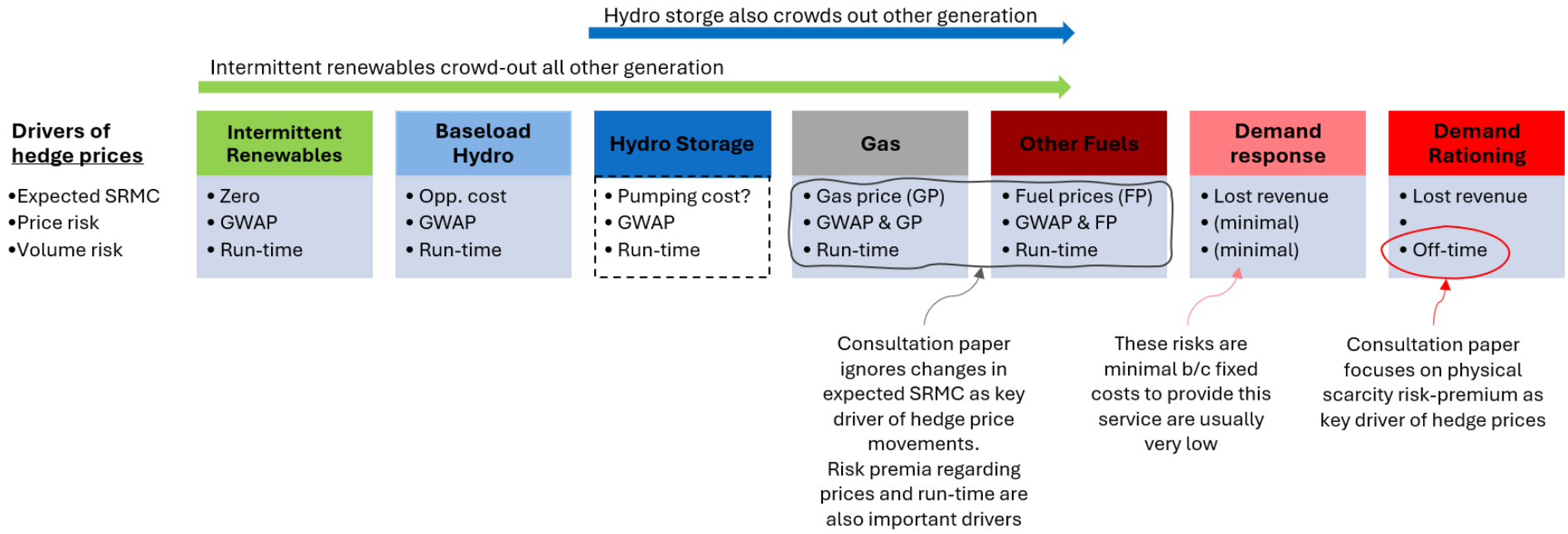
56. Distinguishing the sources of the premium also clarifies what policy can and cannot influence. The largest components — those arising from uncertainty about the future fuel costs of firming plant — are driven by the performance of the domestic gas market and world markets for coal and the equipment used to build renewable capacity. Government policy has no influence over the volatility of internationally traded fuel and equipment prices, so a reliability obligation cannot compress those premiums.

57. Building an LNG import facility does not change this and is not likely to reduce the domestic gas premium. Although LNG can often substitute for domestic gas, it leaves firming plant exposed to global LNG prices.

[11] In a workably competitive market, generators often offer at their SRMC plus a margin, however the analysis remains broadly the same as discussed.

[12] The consultation paper offers no evidence about the materiality of the scarcity premium, let alone any evidence about whether the proposal would materially reduce it. One reason it may be immaterial is that the chances of demand rationing (rolling outages) during winter are incredibly small.

Figure 3: Drivers of hedge prices



58. On the other hand, investment that reduces the electricity system's exposure to the dry-year problem itself — wind, solar, geothermal and additional hydro storage — reduces the frequency and intensity with which high-cost, fuel-dependent firming must be dispatched to conserve water through a dry year. This reduces the fuel risk premium but increases the ROI premium unless smaller scale plant can be deployed.

3.4 The assessment of current arrangements is misguided

59. The paper's central empirical claim — that the market has failed to deliver adequate long-duration firm energy — is asserted rather than demonstrated. This section examines the assessment and finds it biased ,unsupported on the specific question of incentives, and thin on the performance evidence that would be needed to sustain it.

The description of the underlying problems is biased

60. The paper does not consider alternative interpretations of the 2024 experience, and in consequence conflates several distinct phenomena: structural gas decline versus episodic dry-year stress; the exceptional "double-whammy" of 2024 versus forward-looking concerns about the renewables transition; and price effects versus reliability effects. Disentangling these is essential, because the appropriate policy response differs for each.

61. Start with what actually happened in 2024. Daily prices reached about $820/MWh against a 2018–23 winter average near $180/MWh. The Electricity Authority found that this price spike resulted from the *coincidence* of low hydro storage, constrained gas supply and low wind, not from a shortage of investment in firming plant. Thermal plant existed but could not run at full capacity because gas was unavailable; the coal stockpile drew down sharply.[13]

62. The system did not fail. It responded: Meridian escalated its NZAS demand-response option to the maximum (185 MW, saving an estimated 330 GWh over winter — about 7% of national hydro storage). On 13 August, Methanex halted production and on-sold its gas to Genesis and Contact, which brought spot prices down to around $400/MWh.[14] The net result was that the risk of running out of electricity remained less than one percent. This is the profile of a decentralised risk-management regime working under severe stress, not of a regime failing.

63. Several specific claims in the Background chapter overstate or bias the picture. Firstly, the retirement of thermal capacity is presented as leaving the system exposed, with Huntly's Rankine units described as unable to "fill the dry-year gap alone" (para 5). This is misleading. This presumes a single-resource solution that no one advocates — the dry-year gap is covered by a portfolio that includes the Stratford, McKee and Junction Road gas peakers and the NZAS demand-response arrangement. Looking forward, gentailers and other private investors are examining a wide range of options for bringing new long-duration firming to the market.

[13] Electricity Authority (2025, p1).

[14] Electricity Authority (2025, p1).

64. Secondly, the consultation paper asserts that consumers pay a "dry-year premium year after year" because extreme spikes will recur (paras 5–9). No evidence is offered that the 2024-scale spikes will recur; they occurred because of an unexpected collapse in gas output, and the sector has since arranged additional cover — most visibly the Huntly Strategic Energy Reserve for ten years to 31 December 2035, which keeps Rankine Unit 2 in service backed by a solid-fuel reserve of up to 600,000 tonnes.

65. Thirdly, the paper states that a tenor-gap is problematic without supporting evidence (para 9). The tenor gap is real, but it is not peculiar to electricity and should not be seen as problematic.[15] It just means that firming assets are better suited to firms with strong, diversified balance sheets than to project finance — a feature of many capital-intensive industries, not a market failure. New peaking plant was in fact built at Junction Road around 2017; what stopped further such investment was policy risk, not an absence of demand for cover.

66. Finally, the paper leans on the future LNG import facility as evidence that firming is inadequate today (para 9). That is a category error, as a future-focused initiative cannot be evidence about the adequacy of past delivery. In any case, had New Zealand been relying on LNG imports in 2024, and had the recent US invasion of Iran occurred in 2024, spot electricity prices may have exceeded the levels reached in 2024.

The paper offers no evidence about weak incentives

67. The paper's case rests on the claim that market participants face weak incentives to secure long-duration firm energy. It states that "individual participants, acting rationally, may have weaker incentives to secure sufficient long-duration firm energy in advance than desired by consumers", and "may invest in too little long-duration firm energy or do so too late" (para 48); and that "existing settings do not appear to provide incentives that are sufficiently strong or reliable" to deliver the firm generation the system may require (para 52).

68. The claim is advanced on the basis that conditions have changed — that thermal generation "now plays a smaller role than it once did" and the system is "more exposed in dry years" (paras 5–6), so the framework "has not consistently delivered adequate long-duration firm energy as the system has changed" (paras 8 and 47).

69. In reality, gentailers have strong commercial, regulatory and reputational incentives to invest in security of supply as the need arises, and their conduct bears this out.

Commercial incentives

70. The commercial incentives are the most direct, and they follow from the gentailers' dual role as generators *and* retailers. A gentailer whose contracted load in a dry

[15] Long tenor gaps exist for shipping, oil exploration, mining, hotels, commercial property, etc. The tenor gap for domestic rental accommodation is very long too, as most tenant agreements do not match the longevity of the physical property or landlord's mortgage. It tends to occur in any sector combining large sunk capital and long asset lives. I am not aware of suggestions that these gaps undermine investment incentives in their respective industries, or of credible proposals for governments to make it easier for poorly capitalised businesses to enter those industries.

winter exceeds its own generation is *short generation* and must purchase the shortfall from the spot market whose prices rise when hydrology is poor.[16]

71. To manage that exposure, gentailers buy contracts-for-differences (CFDs) sufficient to match any gap in their expected winter load and generation, and they trade their hedge books actively through the year as those expectations change. Those with large hydro reservoirs supplement CFDs with swaptions that they call when their hydro reservoirs fall materially below average.

72. The counterparties to these instruments — on net, other generators — have strong financial incentives to secure firming resources and bring them to market as conditions evolve. This is the market mechanism the paper underplays: the incentive to hold dry-year cover is transmitted through the contracts market to the parties best placed to provide it, and it strengthens automatically as hydro risk rises.

Regulatory incentives

73. The regulatory incentives reinforce the commercial ones. Under the Electricity Industry Participation Code, every retailer must operate a customer compensation scheme that pays qualifying customers a minimum weekly amount once the system operator declares an Official Conservation Campaign (OCC).

74. A second regulatory instrument operates at the physical limit: the system operator applies a scarcity price whenever it instructs load-shedding to keep demand within capacity, sharpening the incentive on generators to secure and husband firming resources.[17] Both requirements pull in the same direction as the commercial incentives.

Reputational incentives

75. The reputational incentives complete the picture. The gentailers are high-profile, closely scrutinised firms operating under a sceptical media and political spotlight. They understand that imprudent conduct leading to a physical shortfall would expose them to political accountability capable of altering their structure, ownership or the market arrangements under which they operate — a standing threat that the events of the 2000s, when direct ministerial involvement in security of supply proved counter-productive, make entirely credible.[18]

Observations

76. There is ample evidence disproving the claim of weak incentives. Generators incurred very high costs in 2024 to keep the lights on. Meridian called successive tranches of Tiwai demand response totalling an estimated 330 GWh (around 7% of national hydro storage), and Methanex halted production and on-sold its contracted gas to Genesis and Contact, bringing spot prices down from a daily average of about $820/MWh to

[16] *Short generation* arises whenever a gentailer's spot market purchases exceed its generation in a given period, forcing net purchases at the prevailing spot price.

[17] The scarcity-pricing arrangement applies an administered price to the market's pricing algorithm when the system operator instructs involuntary load-shedding.

[18] The 2009 Ministerial Review into the Performance of the Electricity Market required Meridian to divest its Tekapo power stations to Genesis Energy, required the government divest the Whirinaki power station, and it required the four largest gentailers to enter into virtual asset swaps.

around $400/MWh.[19] Behaviour of that kind is the signature of strong incentives, not weak ones.

The claims in the consultation paper should be evidenced better

77. The claims in the consultation paper are troubling, for several reasons. Firstly, no estimate of the size of the "incentives gap" is presented. The paper simply asserts that the gap "is too large to ignore" without quantifying it (para 12).

78. Secondly, the logic for the claimed gap seems to depend on an implicit, and higher, security-of-supply standard, reflecting a view that reliability assumptions need to be more conservative than have been used for WEM assessments to-date. This is a characteristic of prudential assurance rather than the efficient, expected-cost benchmark against which the market actually operates. This makes the claim an artefact of the standard applied, not an observation about behaviour.

79. Thirdly, the paper claims that independent retailers and generators need direct access to dry-year cover (para 35). This is incorrect. Independent retailers only need cover to match their load; they have no separate need to procure *dry-year* cover as such. On net, the counterparties to their hedges are the gentailers, and where that counterparty is short generation, the hedge it writes with the retailer drives *it* to secure additional dry-year firming or contract with another generator to do so.

80. The converse applies for independent generators – they benefit from dry year prices and need cover for wet years when spot prices are low. The exception is when they have commitments with their customers that effectively make them a net retailer. In that case, they need hedge cover matching their 'short generation' profile. This will be poorly matched to the market's need for long-duration firming.

Conditions have changed, and the market has responded

81. Consistent with strong incentives, the four largest generators moved quickly once the permanence and scale of the gas shortfall became clear: the Huntly Strategic Energy Reserve now provides cover to 2035, and the same firms have invested heavily in solar, wind and geothermal, with further firming options (including additional hydro storage) under active investigation.

The paper offers minimal evidence about performance

82. Most tellingly, the paper presents almost no systematic performance evidence. It does not analyse the historical WEM record or hydro-reservoir levels against the hydro risk curves. The omission is striking because the available data cut against the paper's thesis.

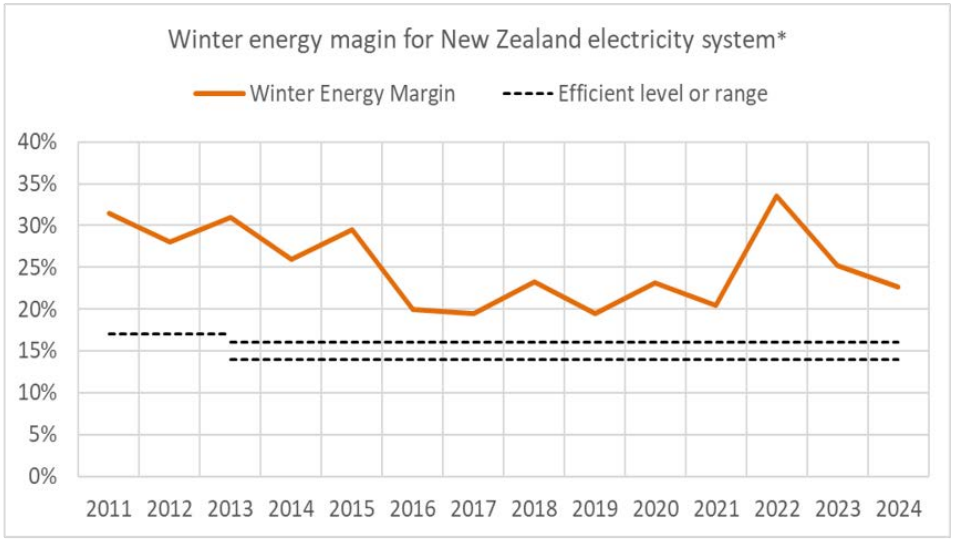
83. Three points bear on this: the actual performance record, perfection in the face of extraordinary shocks is the implied standard, and the diagnosis of the source of the pain arising from winter 2024.

The performance record

84. As shown in Figure 4, the system operator's WEM results since 2011 show the *actual* margin (as distinct from projections) exceeding efficient levels by a considerable margin.

[19] Electricity Authority (2025, p1).

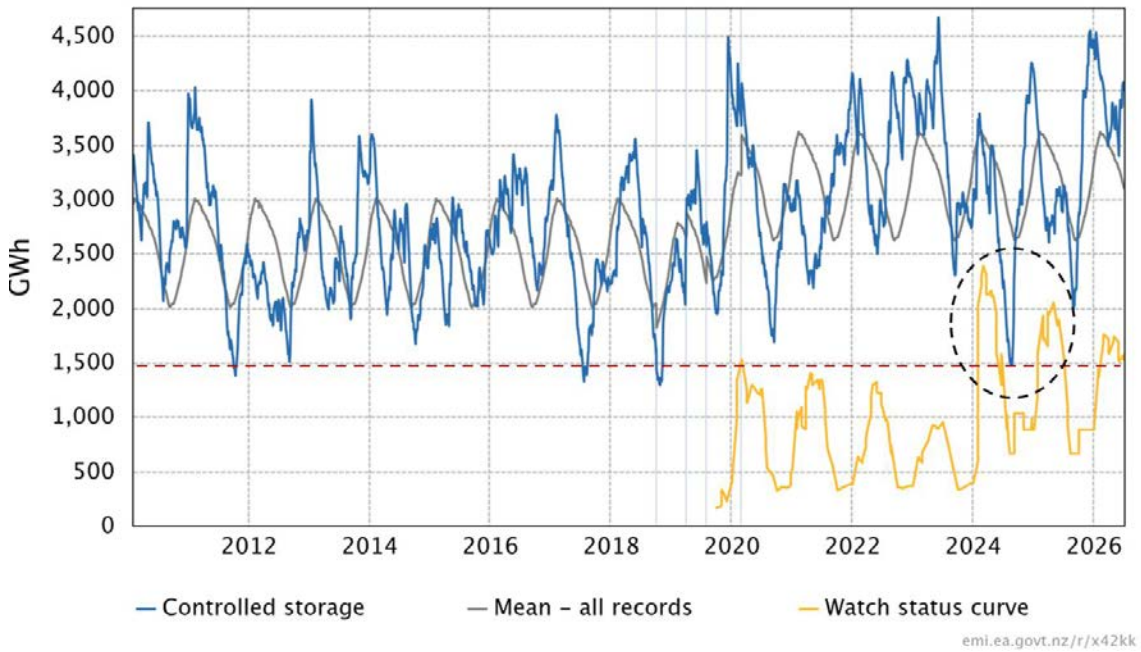
Figure 4: The winter energy margin has been well above efficiency benchmarks



* The WEM is for the low demand growth scenarios as this approximates actual demand

85. The record is also strong on operational performance: at no time in 2024 did hydro storage breach the Watch Curve despite it jumping to unprecedented levels (refer Figure 5).

Figure 5: Hydro storage remained above the 1% hydro risk curve in winter 2024



86. The paper argues that intervention is needed because conditions have changed. However, it is notable the lowest point for hydro storage in 2024 (the red dashed line in the above chart) was about the same as in four previous winters over 2010-2020. On the face of it, operational security of supply worked in 2024 as well as previously despite the change in conditions. But, as discussed earlier, the market had to use more expensive resources to do it.

The paper seems to be judging the market against perfection

87. Second, it is not reasonable to expect any regime — market-based or centrally-directed — to deliver perfectly adequate long-duration firm energy in the face of a sudden supply shock of the magnitude of the gas decline. Imperfect outcomes under an exceptional shock are not evidence of a defective regime.

88. Judged against the relevant historical counterfactual, moreover, outcomes have been vastly superior to the pre-1994 period of direct government control, when rolling winter outages were imposed several times. *No* unmet demand or forced curtailment has occurred for dry-year reasons since the wholesale market began in October 1996 — which makes the paper's invocation of "forced curtailment" rhetorically potent but empirically unfounded (para 50).

The paper misdiagnoses the problem as inadequate security of supply

89. Third, and most fundamentally, the paper misdiagnoses the problem by ignoring the cost side of the ledger. The difficulty New Zealand has faced is not that physical security of supply has been inadequate — on the WEM and Watch-Curve evidence it has not been — but that the *cost* of maintaining it has risen sharply, and that securing lower-cost firming will take time. That is what has weighed on the economy and on industrial firms.

90. Securing *more* physical cover does nothing to help if the cover is expensive; indeed, it makes matters worse. Because the paper attributes the economic harm to elevated reliability risk rather than to elevated cost, it reaches for instruments that add cover — and cost — rather than propose instruments that reduce cost.

91. The misdiagnosis means the proposed solution will do little to restore confidence because the confidence problem is substantially about cost and financial stability, not about physical adequacy. This is the thread that runs from the assessment in this section into the critique of the proposal in section 4.

The paper alludes to considerable economic harm from current arrangements

92. A good portion of the price pressure the paper attributes to dry-year risk has nothing to do with 2024 at all: much of the industrial pain flows from structural gas developments that would have occurred in non-dry hydrology years.

93. A recent macroeconomic analysis commissioned by MBIE estimated significant negative effects on GDP, investment, employment and wages arising from two interacting sources: *low hydro inflows* and the *structural decline in the gas sector*.[20] It appears MBIE has taken the results in this report as indicative of the magnitude of the wider economic effects of current security of supply arrangements. I hope not.

94. The analysis did not separate the economic effects from the two sources, making it impossible to ascertain the periodic dry-year effects (under normal gas sector conditions) from the structural gas sector effects (which has directly affected industrial gas users and indirectly affected industrials via the impact the high gas prices have had on electricity prices). In my view, MBIE should commission further analysis separating the two effects and publish it.

[20] The consultation paper does not provide any references to empirical analysis supporting its claims. My assumption is that MBIE is referring to Sense Partners (2025).

3.5 The problem section understates or neglects important issues

95. The paper asserts that conditions have changed in ways that make the contracting problems it identifies worse: gas-sector decline, the shrinking run-time available to dry-year firming as the system becomes more renewable, and "policy uncertainties." The first two are real and were discussed in section 3.4. The third — policy uncertainty — is mentioned only obliquely and is, on the available evidence, the most important of the three. Its treatment is the subject of this sub-section.

The paper understates a potentially serious policy-uncertainty problem

96. Section 2.3 explained how government itself can become the dominant source of uncertainty for firms making long-lived, irreversible investments. Where a previous administration has undermined investment incentives, it is not enough for the current government to forswear those policies: investors will assume there is some risk that a future administration reverts to them, particularly where the harmful policies served a powerful constituency. When "government is the problem," the set of credible non-interventionist policies shrinks.

97. This is not a theoretical concern in the New Zealand firming context; it is the central finding of the Government's own commissioned review, conducted by Frontier Economics. In their view, a cluster of government initiated uncertainties made new firming investment "virtually impossible": supply uncertainty from the potential NZ Battery (Lake Onslow) project; uncertainty over how a 100%-renewables-by-2030 commitment would be met; and the ban on issuing further licences for offshore oil and gas exploration.[21]

98. The italicised qualification in Frontier's conclusion is decisive for the consultation paper's logic: where policy uncertainty is the binding constraint, the required firming investment will not be made *irrespective of the demand for contracts*.[22] A mechanism that strengthens the demand-side signal — which is, in substance, what the long-term obligation does — cannot fix a problem located on the supply side in investors' risk assessments.

99. The policy-uncertainty diagnosis reframes what a long-term obligation could usefully do. If policy uncertainty is the underlying driver of under-investment, then a durable long-term obligation — one that any future administration would find politically costly to unwind — could function as a *political commitment device*: it would bind future governments toward maintaining firm-energy investment even as they might otherwise revert to uncertainty-increasing policies.

100. This is a genuine potential benefit, and it is the strongest available rationale for the long-term obligation. But it comes at a price, and the consultation paper does not acknowledge the trade-off: a commitment device strong enough to drive investment does so by guaranteeing the associated cost, which shows up in higher hedge prices. The mechanism does not reduce dry-year risk so much as convert an uncertain future

[21] Frontier Economics (2025, p50). Note that Frontier found that, other than flexible capacity for dry-year risk, there are no major obstacles to investment in new renewable generation, and that a strong pipeline of renewable and battery projects was underway; it therefore saw no need for fundamental market-design change.

[22] Frontier Economics (2025, p8).

cost into a more certain present one. These issues are discussed further in section 4.2.

The paper neglects the role of hedging for policy durability

101. Long-dated hedging is the market's own mechanism for allocating dry-year risk to those best able to bear it, and for giving them the cost or revenue stability they want. In my view, adequate levels of hedging are key for policy durability.

The framing conflates the physical and financial aspects of dry years

102. The paper repeatedly presents the reliability obligation as a form of insurance. Both the long-term and short-term layers, it says, "can be understood as forms of insurance against dry-year risk" (para 41). As with any insurance arrangement, the protection comes at a cost incurred regardless of whether the feared conditions occur. As the paper notes, "the fact that an insured event does not occur does not mean it was imprudent to guard against it" (para 41). The claimed payoff is that, when dry-year conditions do materialise, "wholesale prices should be lower and less volatile in a stressed winter" (para 42), with spillover benefits to industry and households (para 43).

103. By describing the procurement of additional firming as "insurance", the paper conflates the physical aspect of a dry year — the shortfall in low-cost energy — with its financial aspect — the exposure of participants to high prices. The conflation drives the paper's central claim that additional cover will deliver "lower and less volatile" prices (para 42).

104. The claim does not survive scrutiny. No matter how much additional firming is procured ahead of winter, New Zealand will continue to experience very high spot prices every now and then. Very low hydro inflows will still occur from time-to-time, and when they do it will be necessary to draw on firming resources with high short-run marginal costs (SRMCs) to conserve stored water. The result will be price spikes.

105. Additional physical cover changes the level of storage at which the expensive resource is called, but it does not abolish the underlying inflow variability that underpins the volatility. This holds regardless of whether the Government also procures an LNG import facility. LNG can supply a substantial quantity of physical cover for future dry years, but its fuel cost is high, so it too has a high SRMC. It will be dispatched only when spot prices are already elevated, and its availability therefore does little to prevent the periodic spot-price spikes the paper implies the regime will smooth away.

106. As explained earlier, growth in renewable energy will reduce the dry-year problem and crowd-out high-SRMC sources of firming. This – rather than the reliability obligations – will reduce the frequency and severity of dry-year events. It will also alter the pattern of spot-price spikes during dry years. Spot prices will be lower when windy and sunny conditions persist during extended dry episodes but spike to very high levels when the reverse occurs (during dry episodes). This occurs due to the dwindling run-times available to recover the fixed costs of high-SRMC plant and because demand response typically has very high SRMCs.[23]

[23] More accurately, demand response has short-run marginal opportunity costs (SRMOCs), which are the firm's forgone gross profit margin plus other marginal costs it must carry such as paying employees.

107. This reality is reflected in the price of winter versus summer hedges. Figures 6 and 7 show that prices for hedges for the 2027 and 2028 winters have declined markedly since May 2025.[24] But so have the prices for the corresponding summer quarters. A large gap between them remains, consistent with the explanation in the previous paragraph. This implies that very high spot prices for extended periods will still occur during dry years, especially when the winter turns out to be cloudier and calmer than usual for the pre-winter and winter period.

Figure 6: A large price gap between 2027 winter and summer hedges remains



Figure 7: A large price gap also remains for 2028 winter and summer hedges



[24] Some readers might be tempted to think the declining hedge prices are due to the Government's announcement that it intends to facilitate the establishment of an LNG import facility. However, that announcement occurred in February 2026, well after prices started declining. Moreover, the possibility of an import facility being operational in 2028 cannot account for the reduction in 2027 contract prices.

Hedging, not additional firming, is the mechanism that stabilises costs

108. If the concern is financial — the exposure of participants to volatile prices — then the appropriate response is financial. Market participants who wish to stabilise their costs must be well hedged, deploying contracts-for-differences, caps, options, swaptions, or a combination of them, with the tenor of the hedge matched to the period over which they wish to smooth prices.

109. Hedging is the financial-protection mechanism for electricity security of supply; it preserves the marginal-cost price signal that underpins efficient dispatch and investment while allowing the hedged party to experience stable financial conditions. The financial distress that generates political pressure in a dry year is, in substance, a consequence of limited hedging by exposed firms — not of insufficient physical cover.

110. It follows that the reliability obligation, being a physical measure, cannot deliver the financial stability the paper promises. Spot prices, and prices for near-term winter hedges, will continue to vary widely with hydro inflows and reservoir levels. Industrial consumers who secure long-dated hedges can insulate themselves from much of this volatility; those who choose not to will remain exposed whatever the obligation requires of gentailers. The paper's suggestion that the regime will "support more stable outcomes for consumers" is not necessarily true.

The seductive alternative — suppressing spot prices — is worse

111. Some commentators contend that the price consequences can be avoided by building firming resources with low short-run marginal cost — additional hydro storage, geothermal, or intermittent renewables — rather than high-SRMC thermal. But adding low-SRMC capacity avoids spot price spikes only if its fixed costs are socialised — spread across all trading periods — rather than allocated to the trading periods in which the resource is used. Only then are spot prices held below the level they would otherwise reach.

112. That may sound like an attractive route to financial protection, but it has two undesirable consequences. First, suppressing the spot price blunts the incentive for wholesale purchasers to hedge, with flow-on effects that weaken the revenue signals supporting generation investment.

113. Second, artificially low spot prices crowd out firming resources with lower overall cost — notably demand response, which typically combines very low fixed cost with very high SRMC. Price suppression thus raises the total cost of security of supply while degrading the market's ability to fund and durably sustain the least-cost firming portfolio.

Implication for policy durability

114. By characterising a prudential measure as insurance, the paper obscures the financial nature of the problem it most wants to solve and directs the remedy toward the physical symptom rather than the financial exposure (§2.1). A regime that undermines hedging incentives risks leaving the underlying financial exposure — and therefore the political cost — substantially unaddressed. Properly framed, the durability question points not to a quantity obligation on gentailers but to measures that deepen and lengthen hedging by the exposed parties themselves.

4 Problems and risks with the proposal

115. This section sets out the key features of the proposal, the conceptual and practical problems with it, and why it is unlikely to permanently restore confidence. Taken together, these issues make the short-term obligation unworkable and the long-term obligation, at best, ineffective and, at worst, counter-productive.

116. The single most important observation is a matter of economic architecture. The paper proposes a *demand-side* instrument to remedy what its own commissioned review identifies as a *supply-side* problem. Section 3 established that the underlying problem is the elevated *cost* of firming (structural gas decline, global input-cost shocks, policy risk), not a deficiency of physical adequacy or market incentives. A demand-side obligation is poorly matched to a cost-and-uncertainty problem.

117. A second, structural concern runs throughout. The paper is exhaustive about the incentives gentailers supposedly lack, yet silent about the incentives of the *regulator* who would now make the very judgements that ministers distrust the market to make — and about whether that role is compatible with the Authority's independence. These overarching problems are the subject of section 4.2.

118. One physical reality frames everything that follows. Policymakers have no influence over hydro inflows. They can only pursue greater physical security by increasing the firming resources available to the system and/or by using existing resources earlier to hold lake levels higher. Both raise cost — higher carrying costs in the first case, and more post-winter spill in the second. Extremely low inflows will still occur, requiring resources with extremely high short-run marginal costs.

4.1 The paper is proposing a centralised prudential-assurance regime

119. As established in section 3.1, the Government is proposing a centralised regime with strong prudential assurance. The consultation paper describes both features accurately in their parts but never names the whole for what it is. The rhetoric throughout — assurance, ensuring, guaranteeing that dry-year risk "will not re-emerge" — plainly signals a prudential-assurance ambition (para 16, Table 1, Action 2.5). This sits awkwardly with the paper's proposed method for the WEM assessment, which (as section 4.3 shows) is in some respects *riskier* than the risk-management status quo it seeks to replace.

120. Another rhetorical flourish deserves flagging at the outset. The paper repeatedly contrasts its proposal with a status quo it characterises as relying on information and market incentives. But the proposed obligations themselves rely on *incentives* — administrative penalties that tilt commercial decisions — not on any direct mechanism by which the Authority procures or dispatches firm energy. In this respect the proposal is not different in kind from the current regime. The paper does not have a mechanism that "restores the system"; it has a stronger set of incentives. The distinction it draws between an incentive-based status quo and a mechanism-based reform is misleading.

The centralised features of the proposal

121. The proposal contains two components, each imposing administrative penalties on parties assessed to be under-providing physical security of supply.

122. *The long-term obligation* would require large market participants to demonstrate access to firming resources sufficient to cover a projected shortfall in the winter energy margin (WEM) relative to a specified standard. A warning would be issued five years ahead of a projected shortfall, a binding obligation three years ahead, and compliance assessed one year ahead (para 69).

123. The paper proposes placing this obligation on spot market purchasers with aggregate winter load exceeding 500 GWh — in practice the four largest gentailers (Contact, Genesis, Mercury and Meridian) and New Zealand Aluminium Smelters (NZAS) (para 59). Each obligated party must secure qualifying cover proportional to its share of expected winter demand, and the obligated cohort together must close 100% of the identified system shortfall (paras 75–76).

124. *The short-term obligation* would apply when a security-of-supply risk emerges despite the operation of the longer-term mechanism. It is triggered if, at any time between 1 January and 31 July, hydro storage falls below a Notification Curve and is projected to remain below it for 21 days (para 121).

125. The paper proposes to set the Notification Curve 1.62 TWh above the Watch Curve.[25] Obligated parties would then have a three-week verification period and a four-week response period to demonstrate sufficient firm fuel cover — physical fuel stocks, firm contracts for coal or LNG, or credible demand-response arrangements (para 128). The short-term obligation would fall on parties producing at least 2.5 TWh of annual generation — effectively the four largest gentailers (para 116).

126. *Penalties.* The paper proposes a minimum penalty of $10 million and a maximum of three times the commercial gain or 10% of turnover, whichever is highest. The stated objective is to "tilt" investment and contracting decisions rather than impose a mere cost of doing business (paras 90–93).

The prudential-assurance features of the proposal

127. The paper claims its aim is an *efficient* level of security of supply. It states, among the aims of the long-term obligation, that the regime should "ensure dry-year risk — and the resulting reliability and price impacts — is at an efficient level" and "efficiently minimise the likelihood of shortages, curtailment and broader economic disruption" (emphasis added). Taken at face value, that is the language of risk management: efficiency implies a cost–reliability trade-off in which additional cover is procured only up to the point where its marginal cost equals the marginal reduction in expected loss.

128. Other aspects of the proposal point the other way. Three features reveal an underlying prudential-assurance orientation in which the trade-off is suppressed.

129. *First, the treatment of the Huntly Rankine units.* The paper repeatedly expresses concern about the ageing Rankines' reliability. In a WEM framework such a concern translates into a low reliability rating, which lowers assessed margins and generates a shortfall requiring more firming. The consultation paper pre-commits the assessment toward conservatism.

[25] The 1.62 TWh figure follows from the paper's assumption that hydro lakes decline at 18 GWh/day for 90 days.

130. It also sits uneasily with the proposed "Expected Scenario" (§ 4.3), because the *most likely* condition of three separately-maintained 240 MW units is that they do *not* all fail catastrophically over the period to 2035. And if hydro generators genuinely believed the Rankines so unreliable, they would already have strong incentives to arrange low-fixed-cost backup — and, as section 3.4 documented, they are working on that. The reliability assumptions applied to Huntly must rest on robust evidence and expert judgement, or the claim that the proposal encourages *efficient* risk management is misleading.

131. *Second, the treatment of intermittent renewables.* The paper presents an unbalanced view of renewables' long-duration firmness relative to thermal plant, without acknowledging that thermal plant is itself imperfectly available. A conservative, asymmetric treatment is again the hallmark of prudential assurance, not of an efficient, expected-cost assessment.

132. *Third, the rhetoric of assurance.* The Minister frames the proposals as working alongside an LNG terminal "to ensure the market invests in the firming capacity and fuel the system requires" (Minister's Foreword, p 4), and the long-term obligation is subtitled "ensuring adequate energy resources are available to meet expected winter demand" (section heading, p 18). That is the vocabulary of guaranteed outcomes, not efficient risk management.

133. The tension matters because it exposes a design choice the paper never confronts. If the Government's true objective were simply to sharpen risk-management incentives, it could apply penalties keyed to *observable outcomes* — for example, penalties for hydro storage falling below a specified level at a specified date. That would tilt the expected-cost calculation directly: participants pursuing risk management would operate lakes more conservatively ahead of winter and secure the resources to do so at least cost; participants pursuing prudential assurance would treat the penalty as raising the cost of bad outcomes and strive harder to avoid them. Either way, an outcome-based penalty avoids the central pitfall of the proposal — the Authority determining the reliability of specific resources.

134. The fact that the Government has instead chosen to have the Authority assess resource reliability and set obligations against quantitative targets shows that it is changing the *method* by which prudent dry-year management is pursued, shifting from decentralised risk management toward centrally-planned prudential assurance. The paper's failure to acknowledge that shift is the source of many of the difficulties that follow.

135. There is a deeper inconsistency here that a careful reader should not miss. The reliance on the Expected Scenario (the highest-probability future) to trigger the obligation is, if anything, *less* protective against genuinely bad outcomes than the current approach, because it places essentially zero weight on the high-impact, low-probability (HILP) tail. A regime that is rhetorically prudential but methodologically indifferent to the tail achieves the worst of both worlds: it raises average cost in the name of assurance while doing little to reduce the severity of the rare events that produce political pain. This point is developed in section 4.3.

4.2 Overarching problems and risks with the proposal

136. The paper canvasses many practical issues but ignores the fundamental ones. It adopts what Demsetz (1969) called the "nirvana" approach: contrasting an imperfect

market against an idealised regulator, rather than comparing feasible market arrangements against feasible regulatory ones. The authors do not appear to have asked the question any serious policy analysis must pose: "What could possibly go wrong under this regime?" This subsection addresses these issues.

The claimed impacts rely on hidden and unrealistic assumptions

137. The paper's benefit story rests on a chain of assumptions that it never makes explicit and never defends. Stripped to its essentials, the claim is that requiring obligated parties to secure more cover will *reduce* the likelihood and severity of dry-year stress and, in turn, *reduce* hedge prices and consumer costs (para 35). Each link in that chain is questionable.

138. To start with, recall the discussion in section 3.3, where hedge prices reflect the expected cost of hydro, expected fuel prices and the expected cost of demand response arrangements, plus risk premiums. An administrative penalty lowers none of these expected costs. With no change in behaviour, a penalty *adds* to the cost of holding an obligated position.

The "value left on the table" assumption

139. The paper's implicit theory must be that the penalty changes behaviour — that obligated parties become willing to incur additional cost now to reduce expected cost later. But that lowers hedge prices only if the additional cover can be obtained at a long-run marginal cost *below* the expected cost of the risk exposure it displaces. If they have already optimised the cost/risk trade-off, requiring more cover *must* raise hedge prices.[26] There is no free lunch.

140. Alternatively, the authors of the paper might be assuming gentailers have knowingly foregone opportunities to source cover more cheaply than the expected cost of remaining exposed — that they have left value on the table. That would be a strong claim about sophisticated, well-capitalised firms with strong incentives to get these judgements right.

141. The paper states that over-investment in firming resources could result in higher overall costs (para 36), suggesting it accepts that participants are *already* trading off the cost of cover against the cost of risk exposure — otherwise more cover could not raise cost. If they are not making trade-offs, the paper must explain why a penalty, rather than the risk exposures participants already carry, is what finally induces them to inform themselves. It cannot have it both ways.

The "dynamic benefits" claim

142. The paper says greater access to firming will support renewable investment, competition and electrification — benefits said to lie "at the heart of this policy proposal" (paras 37 and 43). This conflates two things. It is *short-duration* firming (batteries, peakers, demand response) that supports intermittent renewables by managing within-day and within-week variability; the obligation targets *long-duration* dry-year cover, which does a different job.

143. The dynamic competition-and-electrification claim is unsupported. Indeed, the opposite may occur: if the Authority makes conservative assumptions about

[26] This is based on the realistic assumption that supply curves are upward-sloping.

renewables' long-duration contribution, the regime could actively discourage the renewable investment it hopes to encourage.

The commitment-device benefit — and its price

144. There is one benefit story that does survive scrutiny, and it is not the one the paper tells. If, as section 3.5 argued, policy uncertainty could be undermining firming investment, then a *durable* long-term obligation could function as a political commitment device. A regime that a future administration would find politically costly to unwind would bind future governments toward maintaining firm-energy investment even where they might otherwise revert to uncertainty-increasing policies.

145. That is a genuine potential benefit and the strongest available rationale for the long-term obligation. But it comes at a price the paper never acknowledges: a commitment device strong enough to drive investment does so by guaranteeing the associated *cost*. If penalties are set high enough to ensure investment, then sufficient investment occurs but hedge prices rise to reflect it. The mechanism does not reduce dry-year risk so much as convert an uncertain future cost into a more certain present one. Whether that conversion is worthwhile is an empirical question, which would need to be addressed if the proposal is to be considered further.

The success criterion is mis-specified

146. Consistent with all the above, the paper proposes to judge the framework's success by how effectively it reduces the physical consequences of dry-year conditions (para 44). But that criterion omits the cost side entirely. It is akin to judging a car solely by its 0–100 km/h time while ignoring its price — a test the most expensive car will always win, because performance is bought with cost.

147. The right test for a scheme whose central risk is that it raises prices is whether it reduces the price of *long-duration cover* for a given level of adequacy. On the paper's own reasoning in paragraph 36 (that over-tight obligations may raise costs), a scheme that raises adequacy by raising cost cannot *necessarily* be counted a success. The absence of a cost-based success criterion is not a presentational oversight; it is the analytical gap that allows the paper to claim benefits it has not shown.

Additional cover does not necessarily reduce dry-year spot prices

148. The paper's causal story needs further thought. Having firming providers *contract* one year ahead does not change lake levels or their rate of decline. Resources affect physical security only when *used*, and they are used only when spot prices rise high enough to make dispatch worthwhile. What matters mid-winter is how *early and intensively* firming resources were deployed as lakes were drawn down — an operational, and not necessarily a contracting, decision.

149. If the obligation forces additional firming, that firming is by construction more costly than the cover already held, so it is dispatched only at *higher* spot prices than would otherwise prevail. The obligation does not reduce underlying dry-year risk; it raises the price at which the marginal cover is called (either their SRMC is higher or firming providers need more revenue to cover their additional fixed costs).

150. The short-term obligation carries an analogous but larger hidden cost that the paper does not model. Because it penalises generators whenever the system risks operating below the Notification Curve, it strengthens the incentive to keep storage *above* that Curve. That implies earlier, more intensive thermal use, and higher spot

prices, in the pre-winter and early-winter periods, costs that fall in many non-wet years, not merely in the rare acute events targeted. These pre-emptive costs are considered in further in section 4.4.

151. Taken together, these points establish that the paper's benefit claims rest on hidden assumptions. The recurring reliance on the 2024 experience as evidence of systemic failure (rather than of an exceptional, gas-driven shock) provides a misleading foundation for the entire benefit case.

Regulators are incentivised to make conservative reliability assessments

152. The paper offers no credible explanation for why the Electricity Authority would make *better* decisions than the market about the reliability of firming resources. Its implicit answer is the nirvana one: a benevolent, fully informed regulator will simply get it right. Public choice economics teaches otherwise. Regulators are neither omniscient nor free of self-interest, and the specific incentives they face in this setting bias them predictably toward conservatism.

Information asymmetry runs the wrong way

153. The proposal can improve preparedness only if the Authority both (a) understands supply-side risks and costs *better* than generators and (b) acts on that understanding by requiring them to obtain cover that they would not otherwise hold.

154. Assumption (a) is implausible: the Authority has materially less granular information than participants about plant condition, fuel logistics and contract availability, and less operational expertise than the firms running the assets daily. There is no reason to expect it to out-forecast gas-field operators about gas-field risk, or hydro operators about the value of stored water.

155. Assumption (b) means imposing significantly higher costs on generators and consumers now in expectation of lower costs later, which may not be politically sustainable. The Reserve Bank found this to be the case with its capital adequacy rules. Its 2019 Capital Review lifted capital requirements substantially, on the basis of a risk appetite framework calibrated to a one-in-200-year probability of banking system distress — materially more conservative than the one-in-100-year benchmark used elsewhere — supported by a cost-benefit analysis. Sustained criticism of both the calibration and the analysis followed, including from submitters to Parliament's Finance and Expenditure Committee (who had initiated a banking competition inquiry) and from the Minister of Finance. The Bank announced a review in March 2025 and, in December 2025, revised its risk appetite and eased the settings.[27]

A transparency-asymmetry drives conservatism

156. Here public-choice analysis bites. An official who under-provides and is then embarrassed by a dry-year event bears a large, visible, personal and institutional cost — the agency's competence is questioned, its independence threatened, ministers demand answers. However, an official who over-estimates the need for cover imposes diffuse, hard-to-attribute costs on consumers through modestly higher normal-year prices, for which they are not blamed or exposed by a headline.

[27] https://www.rbnz.govt.nz/regulation-and-supervision/oversight-of-banks/how-we-regulate-and-supervise-banks/our-policy-work-for-bank-oversight/2025-review-of-key-capital-settings

157. Faced with that asymmetry, the rational regulator builds conservatism into every step — the choice of Expected Scenario, the reliability ratings for types of firming resource, the timing of investment projects, the demand growth forecast — producing systematic over-provision relative to the efficient level: exactly the "prudential-lite" drift section 2 predicted for independent agencies whose existence is threatened by adverse outcomes. This is not a criticism of any individual; it is a property of the incentive structure the proposal creates.

The Rankine reliability assumptions illustrate the problem

158. The paper's evident anxiety about the Huntly Rankines will translate, under a conservatively-incentivised Authority, into low reliability ratings that inflate the assessed shortfall — even though the most-likely condition of three separately-maintained units is continued availability, and even though recent SOSA base-case practice has treated them more favourably.

159. If the Authority is to claim its assessments are efficient rather than merely cautious, the reliability assumptions for major resources must be disciplined by robust and independently reviewed evidence. It is important such disciplines are included in the proposal if it proceeds further.

160. The conclusion is not that regulators are malign or incompetent. It is that a scheme which hands a conservatively-incentivised, information-disadvantaged regulator the job of setting quantitative reliability obligations will tend to over-provide cover and increase costs — and will do so in a direction the paper's "efficiency" language disavows but its incentive structure guarantees.

Getting the penalty rate broadly correct is critical — and very hard

161. The penalty rate is not a detail; it is the mechanism. Everything the scheme is meant to achieve depends on setting a rate high enough to alter decisions in the desired direction without being so high that it triggers the unintended consequences discussed below (chilled competition for load, hold-out pricing, higher hedge prices, distortion of the physical/hedged-load boundary). The practicalities of rate setting are discussed further in those sections.

The proposal has far-reaching implications for regulatory arrangements

162. Beyond incentives and calibration, the proposal reshapes the institutional architecture in ways the paper does not foreshadow.

It is likely to compromise the Authority's independence

163. This is the gravest structural concern. By requiring the Authority to assess the reliability of specific resources and set obligations that materially affect firms' costs and the spot price, the proposal effectively makes the Authority a market participant. Its rulings will at times move prices — inviting speculation ahead of each one — and attract intense commercial pressure and criticism.

164. A regulator shaping market outcomes cannot simultaneously continue to be the impartial assessor of market performance. The current design, in which the Authority monitors and sets rules but does not determine resource reliability, keeps that separation intact; an outcome-based penalty (keyed to observable hydro levels, section 5.3) would also preserve it, while the proposed reliability-rating role undermines it.

It creates rich opportunities for gaming

165. The Authority has less information than the system operator and participants and less power than ministers, exposing it to being gamed by all three: by the system operator, whose scenario and reliability inputs it must largely take on trust; by participants, who are incentivised to present positions and resources in whatever light minimises their obligation or maximises the price they can charge for cover; and by the Minister, whose political interests will not always align with efficient outcomes.

Security-of-supply settings will become politicised

166. The proposed annual report to the Minister, coupled with the resource-rating role, will draw the Authority into the centre of political contestation. When a dry-year event occurs — as another one eventually will — the Opposition will blame the Minister, the Minister will look to the Authority, and the Authority's technical judgements will be re-litigated as political failures. The design invites exactly the politicisation independent regulation is meant to insulate against.

Ratcheting effects are very likely

167. Section 2.3 explained why prudential regimes are prone to ratchet, and the logic applies with full force here. Tighter standards cannot eliminate supply-side shocks, because regulators lack perfect foresight. When a large loss materialises, the loss-averse mindset concludes not that the regime was unlucky but that it was too lax — prompting tighter standards, more prescription, more monitoring, more process.

168. Further, because protection from the largest losses breeds diminishing tolerance for smaller ones, and because the fine margins of electoral and coalition politics mean protection never feels sufficient, the tightening does not stop. The result is an ongoing *ratcheting up* of intervention that erodes business-sector adaptiveness and economic dynamism. This process can proceed for decades until the cumulative cost of poor performance finally builds support for reform.

169. The proposal is itself an instance of the ratchet: a response to the pain of 2024 that adds prescription and penalty atop an already-monitored regime. The relevant question is not whether the first turn is tolerable, but where the sequence ends.

4.3 Practical problems with the long-term obligation proposal

170. To its credit, the paper acknowledges the long-term obligation would involve "non-trivial compliance, administration and monitoring costs," would depend on "necessarily uncertain and … contested" adequacy forecasts, and could, "if poorly designed … add cost and complexity without materially improving winter preparedness" (para 51). This sub-section argues the difficulties are more serious than the paper allows, and that several are not matters of design that careful drafting can resolve but structural features of the instrument.

171. The obligation is *potentially* workable with protections for three limitations in WEM assessments: the significant uncertainties that afflict multi-year projections (Limitation A); the use of ad-hoc, non-economic assessments (Limitation B); and the incentives on officials to build in conservatism (Limitation C).

172. In contrast, prices for hedges one to three years ahead reflect the market's expectation of costs, risks and the supply–demand balance and do *not* suffer from

Limitations B and C — motivating the safeguards proposed in section 5. Here the focus is on the problems MBIE needs to address.[28]

Unintended consequences

173. The allocation and design choices in the proposal generate a set of consequences that the paper does not analyse and that, in several cases, run directly counter to its objectives.

The Expected Scenario is riskier than it looks

174. The paper states that the Expected Scenario is the most likely outcome, which to my mind means the scenario with the single highest-probability future. The paper proposes to trigger long-term obligations when the WEM for the Expected Scenario shows a shortfall relative to a specified standard. In effect, the Expected Scenario is assigned a 100% weighting, and zero weight is given to better or worse outcomes.

175. This is, paradoxically, *riskier* than the standard risk-management approach, which weights the full spectrum. It makes the trigger acutely sensitive to which supply and demand possibilities are admitted into the "expected" case — judgements that, under the incentives of section 4.2, tend toward conservatism.

176. It also sits awkwardly with the paper's anxiety about the Huntly Rankines: the most-likely condition of three separately-maintained units is continued operation, so a faithful Expected Scenario would not embed catastrophic failure — yet a conservatively-incentivised Authority will be tempted to embed it anyway.

177. As the Expected-Scenario trigger places zero weight on the HILP tail, a regime marketed as prudential assurance would, in its actual trigger, be indifferent to the rare severe events that generate the political costs it targets.

The WEM assessment is crude and ad-hoc

178. The paper concedes projections are uncertain but never confronts a deeper defect: the WEM analysis is *ad hoc* rather than economic. Not built on a model of profit-maximising producers and welfare-maximising consumers, it contains no mechanism by which higher expected demand elicits higher supply.

179. Further, the calculation of the efficient winter energy margin utilises crude high-level and out-dated estimates of the cost of interruptions to electricity supply.

180. In a workably competitive market with low entry barriers, higher expected demand *induces* higher supply — otherwise money is left on the table. The WEM's assumption-driven supply response cannot replicate this, so a WEM-identified shortfall may merely reflect the system operator's failure to represent the supply response the market would deliver.

Hold-out pricing and implicit coordination

181. A public compliance deadline is a public signal that resource providers can exploit. In principle, knowing that obligated parties must secure cover by a fixed date or pay a penalty, providers are well placed to holdout until close to the deadline and price

[28] Limitations B and C are properties of a centralised, official-run assessment; hedge prices, being market outcomes, are not subject to them, which is why section 5 proposes using hedge prices as an additional gate.

accordingly — the price becoming a positive function of the penalty rate. Even with reasonable competition, the public deadline is a focal point that risks facilitating implicit coordination, since each provider knows its rivals face the same incentive.

182. An important caveat, however, is that some resource providers will also incur penalties if the WEM assessment one-year ahead of a winter reveals a shortage. This will be case for the four large gentailers, potentially reducing their incentives to holdout if failure to contract means the additional resource will not be installed.

183. In practice, the incentives will depend on the treatment of contracts between obligated parties. For example, if a swaption from Genesis to Meridian increases Genesis' load commitments, then the obligation penalises Genesis for making the contract if the WEM assessment leads to penalties. Likewise, similar issues could arise regarding the NZAS demand response agreement with gentailers.

184. The perverse result is that the obligation may make it *harder*, not easier, to secure firming in a timely, cost-effective way.

The revenue model the paper worries about is not fixed by the obligation

185. The paper's own Appendix diagnoses the core investment problem as the absence of long-term contracts, leaving the revenue model too uncertain to support efficient firming investment (para A32). The obligation does not remedy this: it creates no long-term revenue certainty but imposes penalties that make *under-investment* costly for investors in firming, pushing obligated parties to invest despite the very revenue uncertainty identified.

186. If the penalty is high enough to force investment, the party is squeezed from both sides — investment brings uncertain returns, non-investment brings penalties — and its rational response is to raise customer prices to restore its expected return. The obligation converts a revenue-certainty problem into a higher-price outcome; it does not solve it.

The physical-load allocation is the most consequential unintended consequence

187. Allocating by each purchaser's share of *expected winter demand* means, in effect, the load it is expected to buy from the Clearing Manager ("physical load"). This excludes hedge commitments to industrials and retailers, who themselves buy from the Clearing Manager ("excluded load"). This choice has serious consequences for both the level and volatility of consumer prices.

188. On the *price level*: the proposed approach will chill competition for physical load whenever a penalty is a material risk. Obligated parties will resist taking on physical load without a premium for the penalty risk; non-obligated participants, anticipating this, may raise their prices too, especially where their portfolios are less suited to the displaced load. Physical load will tend to pay *higher* average prices, and the higher the penalty rate, the higher their prices.

189. On *volatility*, the effects differ by customer size and are, if anything, more troubling. Large load will be pushed, at the margin, to buy directly from the spot market and hedge its exposure; if it does not fully hedge, the obligation may *increase* its exposure to dry-year events, worsening exactly the harm the proposal is meant to reduce.

190. Regarding small load, as independent retailers never face the penalty, they gain a competitive advantage over obligated gentailers. They can be expected to win small-load customers, so the obligated parties will want to cover their generation by selling

hedges to the retailers. In other words, the proposal creates incentives that tend over time toward *vertical separation*. That may appeal to some, but independent retailers typically hold short-term hedge portfolios (around 12–18 months on average), so migrating small consumers to them may *increase* price volatility for residential and SME customers — again exacerbating the very problem the consultation paper claims to be reducing.

191. One apparent fix — including hedge commitments in the load definition — trades one distortion for another: it makes hedge prices (especially winter hedges) a positive function of the penalty rate and of non-compliance risk. No allocation rule escapes the fundamental problem, because the problem is the penalty itself, not the base to which it is applied.

The obligation does not obviously incentivise the contracting the paper hopes for

192. The paper suggests the long-term obligation will lead purchasers with spare firming to contract it out to others (including independents), deepening the market. This does not follow. If the obligation is assessed on physical supply contracts, selling additional hedge cover does not reduce a party's penalty; if it is assessed on supply plus net hedge position, selling more hedges *increases* the penalty.

193. Neither version gives a party with surplus firming a reason to contract it out — to do that, one would need to penalise *holding uncommitted* firming, which the paper has not proposed. Meanwhile, purchasers *short* of firming (potentially the hydro-heavy gentailers) already have strong commercial incentives to contract for or build cover. The contracting-and-liquidity benefit is merely asserted, and in my view is reaching.

The compliance-adjustment problem

194. The paper asks how the stages should interact if the outlook changes between warning, obligation and compliance assessment (paras 71 and 74). The answer has an asymmetry the paper should confront.

195. If the outlook *improves* materially before compliance assessment, the obligation must be reduced — otherwise the penalty becomes invariant to compliance effort, neutering its incentive effect. Further, obligated parties would be made to bear the cost of the system operator's modelling errors. If the outlook *worsens*, the obligation should in principle increase, but only with safeguards that strip out the effect of any change in modelling methodology.

196. Another factor MBIE should consider is whether keeping the obligation fixed in the face of a deteriorating outlook is likely to be politically sustainable: a future Opposition will press the Minister to "sheet home" any deterioration to obligated parties, and the regime will be tightened accordingly — another instance of ratcheting.

Setting a reasonable penalty rate is next to impossible

197. The general difficulty of penalty calibration was set out in section 4.2. For the long-term obligation specifically, the crux is that the rate must "tilt" investment decisions, and the paper gives little indication that a rate capable of doing so can be robustly identified.

198. Inferring such a rate requires the Authority to reconstruct investment business cases across firming technologies, with all the sensitivity to run-time and tail-risk

assumptions that entails, and to translate a wide range of profitability estimates into a point penalty. The plausible range is wide, the error probabilities are high, and a too-high rate magnifies every unintended consequence just discussed — especially the physical-load distortions. The realistic path is to start low and adjust with experience, which means the scheme's headline investment effect is unlikely to materialise in its early years even as it undermines the Authority's impartiality and independence .

199. A further, litigation-related difficulty attends the "reasonable steps / events beyond control" carve-out the paper contemplates (paras 94–95). Ignoring force majeure and counterparty failure would be unduly harsh; but admitting such defences opens a Pandora's box. Participants will invest heavily in pleading their circumstances, the Authority will be accused of treating like cases differently, and merit-appeal rights would almost certainly have to be written into the Electricity Industry Act 2010 — raising the risk of costly litigation over what are, in substance, contested commercial judgements. This is an Achilles heel of the penalty design, not a detail to resolve later.

The exemption for small wholesale purchasers is too binary

200. The instinct to exempt small purchasers is reasonable on its face — materiality, proportionality and the avoidance of entry-chilling compliance costs all point that way. The problem, however, is that a small generator (in terms of share of total winter energy supply) could be a significant provider of long-duration firming energy. Nova Energy may fit into that camp.

201. It is important to avoid exempting potentially material providers of long-duration firming energy, as that exacerbates the holdout problem mentioned earlier. This suggests that a generator's share of winter firming energy should be used as the basis for allocating the obligation. Moreover, it is the provider's ability to increase supply that matters, suggesting a low threshold (based on average shares) would be desirable.

202. More generally, the proposed exemption is too binary: full obligation above the threshold and nothing below it (paras 59–61). This produces the equity problem the paper identifies (some load that contributes to the shortfall bears no obligation to help close it) and reinforces the competitive asymmetry described above (exempt independents gain an advantage over obligated gentailers).

A graduated design would be better

203. Exempt purchasers could be required to hold hedge contracts covering a very high percentage of their expected winter load, with the Authority merely confirming a genuine counterparty — not assessing the reliability of underlying resources.

204. Compliance costs would be a fraction of what would be required under the full obligation, and a penalty for shortfalls would strengthen small purchasers' incentives to enter long-term contracts, deepening the contract market and mitigating the equity concern.

Other practical issues that need consideration

205. Two further practical matters deserve emphasis.

Regulatory capability and consistency

206. The compliance framework requires the Authority to determine whether a purchaser has secured "enough" cover "of a kind that qualifies," properly allocated and free of

double-counting. Where contracts are relied on, the Authority will need to determine whether they confer a "sufficiently clear and enforceable entitlement."

207. These are demanding judgements with major financial implications and direct effects on prices for firming contracts. Making them well requires expertise the Authority does not obviously possess at board and senior executive levels, which is where they would be signed off. The process must yield *consistent* outcomes across parties and over time to withstand challenge. It would be prudent for MBIE to give serious consideration to these issues, and the budget implications for the Authority.

Complexity will grow, not shrink

208. The paper's own comparator — Australia's Retailer Reliability Obligation — shows forecast-based adequacy mechanisms become complex and administratively demanding, and the paper rightly counsels caution (paras 106–109). There is no reason to expect the New Zealand scheme to remain simple: the public-choice incentives of section 4.2 will drive more rigorous processes, heavier information requirements and tighter control over time (§4.2).

The market and contracting problems remain

209. Most fundamentally, the long-term obligation does not solve the problems the paper says motivate it.

It does not close the tenor gap

210. The paper identifies the tenor gap — between the 10–15-year (or longer) contracts firming investors may need and the shorter horizons buyers will commit to — as a core weakness. But the obligation can be met with cover contracted only *one year ahead*. An instrument satisfiable with one-year cover cannot close a gap defined by the scarcity of ten-year commitment.

211. The tenor gap is real but is better understood as a feature of capital-intensive industries generally: firming assets suit firms with strong, diversified balance sheets rather than project finance — not a market failure. The obligation neither creates the long-dated revenue certainty investors need nor removes the reason buyers avoid long commitments.

It does not remove the policy and technology risks that deter investment

212. The paper acknowledges (in its Appendix) that decarbonisation-policy uncertainty, transition risk and consenting risk raise the cost of capital for firming investments (para A39). The obligation removes none of these; they continue to feed into the price required to develop firming — and by adding a penalty risk atop policy risk, it may raise that price further.

It rests on a mistaken view of the Huntly investment-timing problem

213. The paper treats Huntly's continued availability as chilling investment in replacement firming and worries that the ageing units cannot be relied on indefinitely (para 9). But the three Rankine units are three separate 240 MW units, not a single block. The commercial case for replacement rests on the prospect of *one* unit failing, with low fixed-cost backup resources (demand response) bridging the interim — a sensible portfolio response, not a market failure.

214. And the so-called chilling effect of the Strategic Energy Reserve is efficient wherever replacement investment would itself be inefficient: entry is warranted only where an

entrant's *variable* cost is low enough that it could out-compete the Rankines and recover its fixed costs and is not warranted otherwise. The paper reads efficient restraint as a defect.

4.4 Practical problems with the short-term obligation proposal

215. The short-term obligation is particularly problematic. The paper offers no credible account of how the Authority would make reliability determinations *in real time*, under acute time pressure, on limited information — preparing a paper, checking it with an expert and obtaining a board decision within a compressed window while commercial negotiations hang on the outcome. This sub-section sets out why the instrument is likely to be unworkable and counter-productive.

216. Unintended consequences

The trigger suppresses the very trade-offs generators are best placed to make

217. The paper selects an 18 GWh/day storage-decline trigger because, tested against history, it "would have captured" the concerning years without catching benign ones (paras 121 and 125). But keying a hard obligation to a mechanical trigger removes the real trade-off between the upfront cost of arranging resources now and the option value of waiting. Gentailers make that trade-off carefully because they bear the costs and benefits of it. They consider weather forecasts, the opportunity costs of conserving hydro reservoirs, and the availability and cost of the specific resources at their disposal. A mechanical trigger does not.

218. Worse, as with the long-term obligation, the deadline is a public focal point inviting resource providers to holdout, with their asking prices a positive function of the penalty rate. This is likely to raise mid-winter spot prices and increase rigidity precisely when flexibility and agility is most valuable.

219. The removal of some trade-offs means average wholesale prices will be *higher* than otherwise. The obligation may avert some acute episodes, but unhedged and poorly-hedged purchasers — some industrials, some independent retailers — may face higher *average* spot exposure, harming their businesses.

It strengthens the incentive to hoard hydro, raising pre-winter prices

220. Because breaching the Notification Curve exposes generators to significant cost, the obligation strengthens their incentive to keep storage *above* it — implying earlier and more intensive use of thermal generation, resulting in higher spot prices in the pre-winter and early-winter periods. These costs are incurred in ordinary years, not just the rare acute events. This is the short-term obligation's central hidden cost.

The load-and-commitments base distorts contracting

221. Imposing the obligation in proportion to share of load and contracted commitments creates an incentive for generators to charge higher prices to customers seeking contract renewal and to new enquiries (whenever a penalty is in prospect). This is because contract commitments increase the generator's potential penalty bill. Even generators with ample spare capacity may do this.

222. The result is higher prices for customers into and during winter, and — if the base includes hedge commitments — higher winter *hedge* prices too.

Continuous supervision imposes real operational cost

223. Requiring obligated generators to disclose positions continuously so the Authority can "maintain oversight" (para 130) is, in substance, a prudential-supervision regime. Its cost is not merely continuous reporting (much needing senior-management sign-off); it is that generators will constantly seek signals that they are operating consistently with the Authority's view.

Setting a reasonable penalty rate is next to impossible

224. The problem of calibrating the penalty rate is sharper here than for the long-term obligation. To set a rate that alters fuel-procurement decisions, the Authority would need to run a hydro-optimisation model across a range of cost parameters spanning the futures it thinks possible, extract the gradient of the trade-offs, and feed that into a model determining the penalty rate.

225. The plausible range is wide and error probabilities high, so — as with the long-term obligation — the realistic course is to begin low and adjust with experience. A rate too low changes nothing; a rate too high magnifies every distortion in section 4.4 and compounds the hydro-hoarding effect.

226. The same force-majeure difficulties arise: admitting 'events beyond control' invites resource-intensive pleading and the potential for differential treatment. Again, merit appeal rights may need to be introduced into the Act.

Other practical issues that need consideration

227. The deepest problems with the short-term obligation are practical, and they are severe enough to call the instrument's workability into question.

The Authority cannot assess the reliability and credibly of firming resources quickly

228. The framework seems to assume generators will pay for additional cover *before* knowing how the Authority will judge its contribution. That is unrealistic. In a compressed window, a generator negotiating for new fuel or firming needs the Authority's assessment of that resource's reliability and credibility *before* finalising price and terms — yet the Authority cannot deliver rigorous, board-endorsed assessments at negotiating speed.

229. Injecting the Authority into time-sensitive, commercially sensitive negotiations creates real risk for both parties, since conditions and prices can move sharply while the assessment is pending.

The reliance on contracts, warranties and indemnities is naïve

230. The paper suggests the Authority could, in most cases, look no further than a "sufficiently robust" contract, relying on warranties and indemnities to discipline counterparties. This underestimates the task: assessing whether an arrangement is "sufficiently firm" may require analysing complex commercial agreements *and* forming a view on the reliability of the physical resources behind them.

231. New Zealand's recent experience shows this is not hypothetical. In April 2024 Nova Energy sought to suspend gas supply to Methanex, arguing a "deliver-or-pay" clause

let it pay compensation rather than deliver.[29] Judging whether the arrangement is "sufficiently firm" turns on the interplay of deliver-or-pay, liquidated damages, liability cap and force majeure terms and the gas behind them — the very analysis the Authority would face at speed.

232. More pointed still, Meridian's dry-year cover from Contact — a swaption and CFD expressly conditional on Contact securing gas — was confirmed in force for 2024, yet on 19 August 2024, at the height of the winter stress, was replaced by a smaller, short-dated CFD.[30] Cover confirmed as firm months earlier was curtailed precisely when dry-year conditions bit.

233. If the approved contractual protections fail during a dry-year event, with significant market and economic consequences, pressure will build for a more intrusive approach. In reality, the contractual short-cut is unlikely to be sustainable overtime.

The board-level burden is likely to be unsustainable

234. Because the assessments carry major commercial consequences, they cannot be delegated to a technical back-office; they require board-level decisions, potentially requiring Authority board members to be on standing availability to expedite time-critical rulings. And, as with the long-term obligation, merit-appeal rights would need to be added to the Act, since decisions of this significance cannot fairly be immune from review.

235. The cumulative picture is of a regulator asked to make a myriad of complex, high-stakes judgements over very short periods, combining fuel and plant-reliability assessments. The burden may ease with experience but will remain substantial. It is doubtful the short-term obligation is workable at all.

If a short-term backstop is needed, a simpler approach deserves consideration

236. Given these realities — and the near-certainty of political pressure for ever-tighter control — ministers who nonetheless believe a backstop is needed would be prudent to consider an *ex post* mechanism (assessing conduct after the event against a clear standard) rather than the proposed *ex ante* one, which requires real-time reliability rulings the Authority is poorly placed to make. The overall conclusion, developed in 4.6, is that the short-term obligation should be abandoned.

4.5 Would reliability obligations have improved outcomes since 2018?

237. A striking omission is the absence of any case study of how the proposed obligations would have performed had they been in place before wholesale prices began rising in 2018. A regime intended to prevent a recurrence of 2024 ought to show it would have improved that experience. The paper does not attempt the exercise, suggesting the proposal has not been road-tested against the very history that motivates it.

The long-term obligation would have increased contract prices

238. Placing obligations and penalties on the four largest generators before 2018 would not have led them to prepare for a gas collapse that not even the gas-field operators foresaw, nor would it have enabled them to avoid the global surge in solar and wind

[29] *Methanex New Zealand Ltd v Nova Energy Ltd* [2024] NZHC 1604.

[30] Meridian Energy, NZX announcements, 15 August 2022, 30 November 2023 and 19 August 2024.

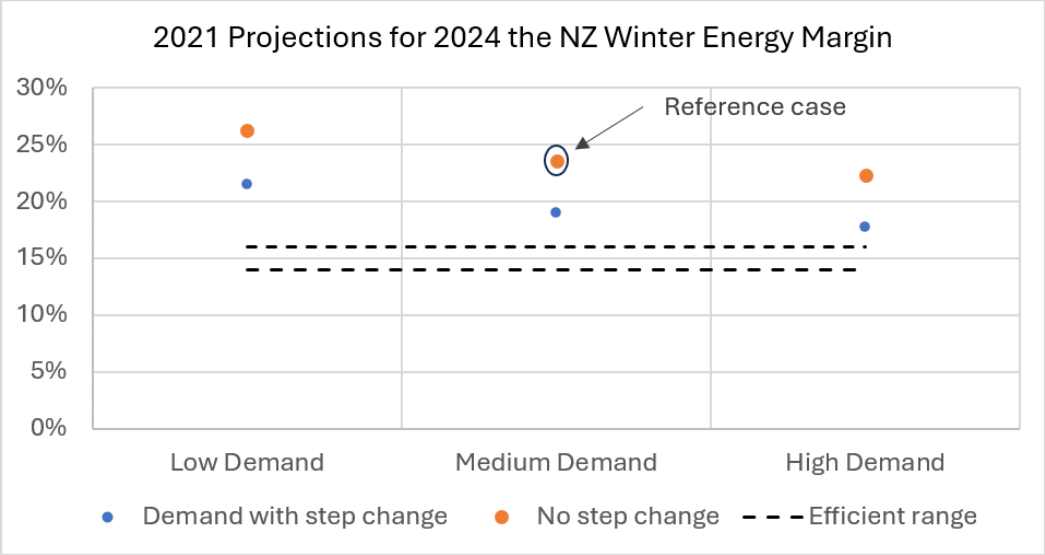
capital costs over 2022–24 or the jump in Indonesian coal prices across 2021–2023. These were exogenous cost shocks to the electricity industry, not failures of foresight that an administrative penalty could have corrected.

The long-term obligation would not have been triggered for 2024

239. The obligation would have improved preparedness only if two assumptions held: the Authority understood supply-side risks and costs *better* than generators, and it *acted* on that assessment. The first is highly unlikely — it implies the Authority knew more about gas-field risk than the gas-field operators.

240. Figure 8 shows the system operator's 2021 projections for the 2024 WEM for the three main demand assumptions, and with and without a 100 MW step up in demand (eg from an industrial consumer). The chart shows the results for the conservative assumption that only existing and committed generation projects will contribute to winter energy supply in 2024.[31] The Reference case refers to the scenario against which all other scenarios are presented as sensitivities.

Figure 8: WEM projections for 2024 made in 2021



241. Two lessons are abundantly clear from the above chart. First, even with high demand growth and the conservative supply assumption, the winter energy margin for 2024 was projected to be well above the 14-16% security standard. Secondly, a Low Gas Supply assumption had no effect whatsoever on the WEM projection for 2024. This is because the system operator projected that low gas output would not bite until 2026:

> *The Low Gas Supply sensitivity assumes that domestic gas production declines substantially from current levels from 2025… Dry year gas supply margins for the Low Gas Supply sensitivity indicate that gas supply will be*

[31] Although the SOSA includes many other supply scenarios, none of them affect the WEM results for 2024. Some affect other assessments, eg the winter capacity margin or the South Island WEM.

constrained from 2026… From 2029 there will be insufficient gas to supply existing gas base load and peaking generation.[32]

242. It seems very unlikely the long-term reliability obligation would have made any difference for 2024. Although the Expected Scenario approach in the proposal might have been significantly lower than the Reference scenario, it will have provided far higher WEM projections than the worst-case scenario shown above in Figure 8 (High Demand plus a step change in demand). Even the WEM projections for the worst-case scenario exceeded the efficient range.[33]

The hedging choices of industrials were a key flashpoint in winter 2024

243. The industrial pain of 2018–24 fell hardest on firms that were *poorly hedged* against a supply shock that proved prolonged. Most industrials hedge up to three years, offering little protection against a multi-year price supercycle; ultra-long hedging (like NZAS's 20-year contracts) is neither available to nor suitable for every large consumer.

244. Hedging benefits more than the hedges parties themselves because it can allow a firm to ride through a dry-year event on average-cost prices for its contracted volume. Without dulling the marginal-cost signal, it reduces the financial volatility that drives firms to curtail or close, and so it reduces political costs. The longer the tenor, the longer the period of financial smoothing and average-cost pricing.

It can be commercially optimal for struggling firms to avoid hedging

245. Crucially, under-hedging can be *privately rational and even socially optimal* for a struggling industrial. If temporarily elevated hedge prices would render it unviable, carrying on unhedged — and closing later only if events turn against it — can be worth more than closing now, because closure is costly to reverse.

246. The difficulty is not the under-hedging per se but the *opportunistic communication* that follows: no struggling firm will announce a no-hedging strategy, since that would unsettle customers, raise financing costs and, for a listed company, weigh on its share price. If the gamble pays off, the firm stays silent; if not, it presents itself as viable "at competitive hedge prices" and argues for intervention.

247. Ministers rarely know the full circumstances, which is exactly why the *stress-test regime* — giving the Authority visibility of participants' spot exposure ahead of stress — is better targeted than a physical obligation that changes nothing about who is hedged. A long-term obligation would have altered none of this. It would have raised contract prices across the many non-collapse years without touching the hedging behaviour that actually drives the political tension.

The short-term obligation would likely have increased spot prices

248. In August 2024, with storage low and gas scarce, obligated parties' realistic options for additional cover were few and lumpy: convince Methanex to reduce its production

[32] System Operator (2021, pp31-32).

[33] Of course, the reliability obligation would likely have altered behaviour had it been in place, which has not been considered in the above discussion. But any such behavioural effects would only have served to increase projected WEMs.

and on-sell its contracted gas or face the rapidly growing prospect of having to curtail customer demand if the weather remained dry. In that setting the price of the Methanex option would be a *positive function of the cost of the alternatives and of the size of the penalty*.

249. A penalty layered on top would have handed Methanex additional pricing power precisely when the system was most stressed — tending to *raise* acute-window spot prices, not lower them.

Would the regime have made any difference for industrial consumers?

250. Given the WEM projections discussed above, it seems unrealistic to assume the reliability obligation would have contained spot prices to levels similar to dry year episodes over 2010-2018. Suppose, against my views above, the regime had trimmed the 2024 spot peak from roughly $820/MWh toward, say, $600/MWh — would that have materially restored confidence or relieved the political pressure? For an unhedged industrial facing an existential cost shock the answer is almost certainly no — $600/MWh would still have been ruinous for some of them. Their viability turns on their *hedged* position and output-market economics, not on the exact height of a peak it was exposed to.

251. Well-hedged industrials came through 2024 quite differently: some kept operating, and some paused because their hedge positions made reducing their electricity demand more profitable than consuming it. They get the financial benefit of the hedge cover while avoiding the financial cost of purchasing from the spot market.

252. The distress the proposal invokes is a financial-exposure problem — addressed by hedging and other measures (§5) — not a physical-adequacy problem. Further, a regime that raises average prices while shaving occasional peaks may leave exposed industrials worse off, not better.

4.6 Concluding comments

253. For a proposal of this ambition and cost, the absence of numerical analysis is striking. The paper claims the regime would deliver an *efficient* level of security of supply yet presents no modelling of the effect on wholesale or retail prices, no estimate of compliance and administration cost, and no quantification of the “incentives gap” it is meant to close.

254. Both obligations are problematic. Generators already have strong incentives to secure adequate firming resources well ahead of when they are needed, and strong incentives to prepare for and respond to operational setbacks such as an unexpected loss of firming fuel, as their conduct in 2024 demonstrated. Both obligations would make securing alternatives *harder*, not easier.

255. Given the mis-framing of the problem as physical, it is understandable that the Government seeks arrangements that demonstrate proactive firming and penalise its absence: the political cost of a dry-year event far exceeds that of modestly higher normal-year prices, making prudential assurance an optimal *political* strategy (§2).

256. Although the proposed obligations are likely to endure, they will not deliver an enduring solution because they do not materially reduce political costs. High wholesale prices will still occur in dry years because the additional resources required by the long-term obligation will likely have high SRMCs.

257. None of the uncertainties invoked to justify intervention is genuinely new, and because they are real and irreducible, the optimal response is a diversified portfolio of firming with low fixed (and typically high variable) costs, whether the choices are made by the market or a central body.

5 Making the proposal safer and more durable

258. Section 4 identified significant risks with the proposal – not only making it very uncertain whether it will be beneficial but in fact it could harm security of supply. In light of that, this section argues that the Government is acting pre-emptively and should take a "wait and see" approach (§5.1).

259. If the Government is intent on proceeding with its proposal, then it would be prudent to adopt steps that safeguard against the risks involved. This involves adding 'checks and balances' to the application of the long-term obligation (§5.2) and trialling a simpler ex-post version of the short-term obligation (§5.3).

260. Section 4 also concluded that the proposal will do little to restore confidence in security of supply arrangements because it does not address the financial aspects of dry-year events. Section 5.4 proposes steps to improve the political palatability of dry-year events. These would improve policy stability regardless of whether the Government proceeds with its proposals.

5.1 A more cautious approach is warranted

261. It is widely recognised that policymakers face deep uncertainty when considering entirely new policies, for example introducing new laws or fundamentally altering regulatory arrangements. Nevertheless, policymakers tend to be over-confident about the economic effects of their preferred solution or for political reasons ignore genuine uncertainty about effectiveness.[34]

262. A cautious approach is desirable when there is genuine uncertainty about whether the intervention will be net beneficial. When unintended consequences might exceed the benefits of intervention, the policymaker cannot rule out the possibility that acting makes things worse rather than better. In that case the best policy is not to intervene at all or intervene cautiously.[35]

263. This is relevant because section 4 established a strong case that the short-term obligation would raise pre-winter spot prices and impede generators' access to firming, and the long-term obligation would raise the price of cover without reducing dry-year risk. These risks are amplified by the considerable uncertainty about the appropriate penalty rate.

264. The case for taking a wait-and-see posture is reinforced by the reality that the underlying physical dry-year problem is likely to diminish over time as wind, solar and geothermal reduce the system's reliance on hydro storage (refer section 4). This

[34] North (1990) refers to *instrument rationality* to explain these situations. In essence, industries are complex, so the informational feedback from current and previous policies is inadequate to inform policymakers about how the industry operates and how it would behave under new policies.

[35] Brainard (1967) shows caution is optimal when policymakers take a risk management approach to decision-making and Barlevy (2009) shows the 'wait and see' approach can be optimal when they face deep uncertainty and their goal is to avoid large adverse outcomes.

means the cost of waiting is falling, while the cost of a poorly calibrated intervention, once entrenched and subject to the ratchet, is not. Acting later, with better information, is better policymaking.[36]

5.2 Safeguards to make the long-term obligation safer

265. If the Government is intent on proceeding with the long-term obligation, two provisions should be adopted to safeguard against two of the risks identified in section 4.3: the ad-hoc aspect of WEM assessments (Limitation B), and the tendency for conservative judgements to be built into every step of determining obligations and assessing compliance (Limitation C).

Hedge prices and risk premia should inform views about winter energy adequacy

266. Section 4.3 explained that WEM assessments are not based on an economic model with profit-maximising producers. Instead, they rely on ad-hoc assumptions about supply and demand.

267. In contrast, prices for hedges one to three years ahead reflect, among other things, the expected balance of supply and demand over that timeframe. In my view, the regime should allow the Authority to use prices for long-dated ASX electricity futures contracts as a separate, market-based, indicator of the likely adequacy of winter energy supply to meet demand.

268. One approach would be to compare the price of winter contracts maturing in three years against the price of summer contracts maturing in three years. If that relativity sits within a specified maximum, based on historical data, the WEM assessment would be adjusted accordingly.

269. A more sophisticated approach would use econometric analysis to estimate, on an ongoing basis, the risk premium embedded in winter contracts. This approach adjusts for the fact that the simple price relativity may be driven by changes in the *expected marginal cost* of winter firming rather than by an expected *shortfall* — a distinction that matters, because section 3.3 showed hedge prices reflect expected costs, revenue risk premia and scarcity premia. The estimated risk premium would then be used to adjust the WEM assessment.

270. Alternatively, the Authority could adopt a stage-gate approach to determining whether to impose obligations. The first gate would be the WEM assessment, the second would be the relative hedge price assessment and the third would be the risk premia assessment. Each assessment would be assigned a *green* light if it clearly implies action is required, a *red* light if it clearly implies no action is required, and an *orange* light if it is unclear. Under this approach, long-term obligations would be

[36] The precautionary principle is sometimes used to argue for proactive intervention. This applies only when there's reason to believe a large irreversible adverse event is about to occur, intervention is effective and in the right direction and there are no countervailing irreversible effects from intervening. These assumptions do not apply here.

imposed only when all three indicators are given green lights. No obligation would be imposed if any indicator is red.[37]

271. A similar approach could be adopted for the final compliance assessment one year ahead of a winter. If the relative prices for futures contracts for next winter, or the relevant risk premia, are within specified limits, then the Authority would not assess compliance with the obligation if one had been formally notified.

272. The value of these gates is that they discipline an assumption-driven administrative judgement with a market-based one that is harder to bias. One consideration is whether the ASX futures markets is sufficiently deep for the relevant tenors.

Independent experts should be involved in reliability assessments

273. Section 4.3 also explained that regulators face incentives to build conservatism into every step of the process. If the stage-gate approach is not adopted, or is not judged a strong enough safeguard, the Authority should draw on independent parties. It could appoint an independent panel of international experts in generation-asset and fuel-source reliability, whose assessments the system operator would be required to adopt in preparing its WEM analysis. Where the system operator declined to adopt them, it would have to give reasons, and the Authority would determine whether to accept those reasons.

274. An alternative is to task the Security and Reliability Council (SRC) with preparing WEM assessments independently of the system operator, with the Authority adopting whichever projection is the more convincing.

275. Neither approach will *eliminate* bias. An expert panel has its own incentives, and the SRC comprises members from the electricity industry. But either approach should help to make conservative assumptions visible and contestable rather than embedded and unexamined.

A sunset provision should be adopted

276. Even with the above protections, the long-term obligation may suffer ratchet effects over time (§4.2). Fortunately, the underlying dry-year problem should recede as solar, wind and geothermal supply a larger share of electricity. If the obligation is adopted, a sunset provision should be included in the Electricity Industry Act 2010, ceasing the regime six years after commencement.

277. This means the scheme would be reviewed after five years of operation, and it would only continue if there was sufficient Parliamentary support. The rationale for a sunset provision, rather than a mere review clause, is that governments find it difficult to prioritise legislation removing regulation even when a review concludes removal would be beneficial overall — the more so for regulation ostensibly protecting security of supply, where the political costs of being seen to weaken protection are asymmetric (Appendix 1, §A1.3). A sunset provision counterbalances those forces by making continuation, rather than removal, the action that requires positive effort.

[37] The Reserve Bank uses a similar stage-gate approach to determining whether to intervene in the foreign exchange market. Refer https://www.rbnz.govt.nz/financial-markets/foreign-reserves/foreign-exchange-intervention.

5.3 A simpler short-term obligation should be considered (if necessary)

278. As section 4.4 argued, the short-term obligation is intrusive and problematic for workability. Generators operate under considerable time pressure when hydro reservoirs fall well below average, and it is neither practicable nor necessary to have the Authority so deeply involved in operational decision-making — generators already have very strong incentives to procure and use long-duration firming.

279. However, if the Government is insistent that a short-term backstop is needed to provide assurance, it would be better to specify an ex-post incentive scheme based on observable hydro reservoir levels and allow obligated parties to trade the obligations with each other. The consultation paper dismisses ex-post approaches too quickly, in my view. MBIE should properly consider a regime imposing penalties for breaching the Alert or Watch Curves, with a low penalty for breaching the Watch Curve and a higher penalty for breaching the Alert Curve, both set low initially and raised gradually only if deemed necessary.[38]

280. Although I do not favour even this scheme, it has three advantages over the consultation paper's ex-ante design. It leaves decisions about resource reliability with the players who have the incentives and information to make the tough trade-offs. And, by removing the Authority from real-time reliability rulings, it avoids compromising the Authority's ability to assess market performance impartially (§4.2).

5.4 Obligations on industrials are needed to improve policy durability

281. The consultation paper focuses on prudential assurance aimed at improving physical security of supply. As discussed in Appendix 1, prudential policies are usually accompanied by financial-protection policies, because large shocks will still occur and it is generally too costly to materially reduce their frequency and severity. That logic applies directly to electricity security of supply, where *hedging* is the financial-protection mechanism.

Industrial-sector exposure to spot prices drives political costs

282. Section 4 concluded that the proposal will do little to restore confidence, because it does not reduce the political costs of dry-year events. Those costs are driven by two factors. The first is the financial impact of dry-year events on poorly hedged industrial consumers, which can drive struggling firms to curtail during an event or to close permanently. The second is that high spot prices are routinely read as a warning of impending shortage, when they are better understood as the market using high-cost resources to keep physical risk low.

283. The mechanism connecting hedging to both problems is often misunderstood. Hedges preserve marginal-cost pricing signals while allowing the contracting parties to adopt average-cost pricing for their contracted volumes; the longer the tenor of the

[38] Alternatively, the rate of compensation specified in the Customer Compensation Scheme could be increased. This Scheme applies when Official Conservation Campaigns operate. This would avoid the need to develop a new penalty regime; however, the Minister may consider the scheme too remote and unlikely to affect generator choices.

hedge, the longer the period over which prices are smoothed. This separation matters because the two functions it reconciles are usually thought to be in tension.

284. Marginal-cost pricing is essential for productive efficiency, as it directs scarce resources to their highest-value uses and signals when new investment is warranted. The downside is that it exposes buyers to large, volatile price swings. Hedging resolves this tension by not interfering with the spot price signals while allowing the hedged buyer to experience more stable financial conditions. The financial distress that generates political pressure is a consequence of *limited* hedging by exposed firms.

285. Why, then, do some struggling industrials choose not to hedge? As section 4.5 explained, the answer is not irrationality. For a marginally viable firm, under-hedging a dry-year exposure can be privately — and even socially — optimal because buying cover at temporarily elevated prices may itself precipitate the closure the firm was trying to avoid

286. The difficulty lies in the *opportunistic communication* that follows rather than in the under-hedging itself. A firm that stays silent when its gamble pays off but attributes its distress to high *winter* electricity prices when it does not, presents ministers with a case for intervention they cannot easily verify. That is why credible, independent information about firms' exposures is so valuable, and it motivates the disclosure-based measures developed below.

287. The winter-2024 experience illustrates the pattern. Several firms that curtailed or closed operations — including pulp and paper businesses — cited high wholesale electricity prices, yet the Authority's review found that hedges had been available to them, and that most large industrials had in fact hedged and were insulated.[39] Distinguishing genuine competitiveness problems (driven by output markets, exchange rates and borrowing costs) from the consequences of a hedging choice is difficult from the outside, but it is central to understanding whether electricity security of supply is working well or not.

288. For these reasons, policymakers should consider initiatives that encourage industrials to hedge a large portion of their expected winter load, or to otherwise manage their spot-price exposure more proactively.[40] Two are developed below: strengthened financial disclosure through the stress-test regime, and a more interventionist, but flexible, mandatory-hedging obligation.

The stress test regime could require greater financial disclosure

289. The stress-test regime is one of the Authority's most important — and least understood — instruments for managing the *political* economy of dry-year events. Its original rationale, when introduced in 2011, was to reduce the credibility of opportunistic lobbying. It does this by arming the Authority with information about participants' spot-price exposure ahead of periods of stress, so that ministers and commentators can be assured that wholesale market purchasers understood the

[39] Electricity Authority (2025, p2).

[40] Applying the long-term reliability obligation to all industrials purchasing from the spot market may lead some of them to purchase from gentailers to avoid the compliance costs, but that is a rather ad-hoc basis for encouraging higher levels of hedging. And higher levels of hedging could be beneficial even if the long-term reliability obligation proposal does not proceed.

risks they took on — and so that under-hedged firms cannot readily attribute self-inflicted losses to the market.

290. On the evidence, the regime worked: opportunistic lobbying was common before 2011 but largely absent through the tight winters of 2012, 2018 and 2019; its re-emergence in 2024 suggests the regime needed strengthening. The Authority has already acted, extending the stress-test horizon from the coming quarter to the next quarter plus eleven following quarters, and requiring disclosure of actual hedge-cover ratios with sector benchmarking, from May 2025.[41]

291. Building on that direction, the Authority should consider imposing more in-depth disclosure obligations on wholesale purchasers whose test results fall below specified minimums. Focusing on the winter-energy issue, minimums could be set for the cover ratio and, perhaps, for one or more of the cashflow and shareholder-equity ratios.

292. To illustrate, additional disclosure could be required of purchasers meeting three thresholds: over the previous year they accounted for more than 1% of wholesale-market purchases; their cover ratio in their latest test is below 75%; and either their equity ratio in their latest test exceeds 25% or their cashflow ratio exceeds 10%. The aim is to capture only sizeable purchasers that are poorly hedged and for which electricity is a material cost.

293. Purchasers meeting those thresholds would disclose to the Stress Test Registrar (currently NZX) how their finances and viability would be affected by purchasing hedges, at current market prices, sufficient to cover 100% of expected winter load one year and three years ahead. Where such cover would lead them to close some or all their plants, the purchaser would have to explain any non-electricity factors driving its difficulties and provide summary financial information.

294. On a subsequent announcement of temporary or permanent closure, the Registrar would provide a non-financial version of the disclosure to the Authority, who would pass it to the Minister and publicly release it shortly afterwards. This directly targets the incentive to attribute pre-existing difficulties to the current dry-year event.

295. The main objection to be weighed is that mandatory disclosure of commercially sensitive financial information imposes a real compliance burden and could, if poorly designed, expose firms to competitive harm. That is why the thresholds are deliberately narrow, why the publicly released version is non-financial, and why disclosure of underlying detail is triggered only at the point a firm goes public with a closure that invokes electricity costs. In effect, the regime asks firms to substantiate, to a confidential registrar, the claims they are likely to make in public.

Consider introducing a mandatory hedging obligation

296. A more interventionist option MBIE should consider is empowering the Authority to impose *flexible mandatory-hedging obligations* on industrials that purchase from the spot market.

297. The obligation would require industrials to cover their expected winter load with a portfolio of hedges spanning one to several years ahead of winter, with an average

[41] Electricity Authority (2025b, section 5).

duration of at least 18 months, assessed one year ahead of each winter.[42] Most industrials already do this, with NZAS being exceptional with 20-year hedges.

298. Two flexibilities would be built in. First, an obligated industrial could reduce the winter load caught by the mandatory obligation by:

    a. taking some or all of it off the spot market through fixed price contracts with gentailers, or

    b. entering demand-response agreements with gentailers covering a large portion of their usual winter load.

299. Second, an industrial could obtain an exemption by completing two requirements:

    a. in each March quarter, publicly disclosing the impact that the mandatory hedge requirements would have on their business viability and publicly committing to stay-in-business for the next 12 months, and

    b. providing the Stress Test Registrar with information that shows they have sufficient financial resources to keep their commitment in (a).

300. The first flexibility encourages industrials to seek long-term supply and demand-response arrangements with retailers (most likely gentailers) – in effect, easing vulnerable industrials away from the spot market and onto arrangements more suitable for them. Retailers have strong incentives to offer sharp pricing to any industrial that might close their plants. [43]

301. The second flexibility seeks to minimise the conflation of structural (eg the gas sector decline) and cyclical effects (eg dry year effects) in the way that industrials communicate about their business closure decisions. This flexibility is only needed if an obligated industrial wishes to remain exposed to spot electricity prices.

The case for mandatory hedging on industrials

302. A mandatory hedging obligation attacks the actual driver of dry-year political costs — industrial financial exposure — rather than the physical-adequacy symptom the reliability obligation targets. In the framework of section 2, it is a *financial-protection* measure complementing, not substituting for, physical security.

303. It has several attractions. It is far better targeted than the reliability obligation: it places the requirement on the exposed parties themselves, rather than obliging gentailers to hold system-wide cover. It removes the opportunistic-communication problem, because a firm that is either hedged or has formally disclosed its unhedged position cannot credibly blame the market for a self-selected exposure.

304. Further, the option strengthens, rather than distorts, the contracts market. Additional demand for winter hedges or supply contracts gives generators information and incentives relevant relevant to supporting firming investment. And the built-in flexibilities preserve the firm's freedom to choose how, and whether, to manage its exposure, so long as it does so transparently.

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[42] The average duration parameter needs to be long enough to span a dry-year event and blunt the opportunistic-communication problem, but short enough to avoid the issues that make ultra-long tenors unsuitable for most industrials (refer §3.5).

[43] Industrials offer large chunks of baseload (24x7) demand and long-term evergreen contracts would suit both parties.

The case against imposing mandatory hedging obligations on industrials

305. The most principled issue is that it would tilt commercial hedging choices away from what can be privately and socially optimal in a first-best world. The counter argument is that the political implications of under-hedging means we do not live in a first-best world. In my view, under-hedging by (some) industrials is creating pressure for adoption of a far less efficient system, and one that is likely to be less effective at securing adequate security of supply.

306. The most significant practical issue is that mandatory hedging obligations could force a marginal firm to buy cover at temporarily elevated hedge prices, precipitating the closure the policy is meant to guard against. The exemption mitigates this, so that closure only occurs when it is driven by structural forces.

307. There would also be penalty-calibration and enforcement issues similar to those analysed in sections 4.3 and 4.4 — how high should the penalty be and how are "reasonable steps" and force-majeure defences to be handled without inviting litigation.

Assessment

308. On balance, mandatory hedging on industrials is better matched to the problem than the reliability obligation, because it addresses financial exposure directly and works largely through disclosure and the contract market rather than through administrative reliability rulings. But it is not costless or risk-free, and the design choices — the duration parameter, the details regarding the flexibility provisions, the definition of covered firms, and the penalty — determine whether it helps or harms.

309. Consistent with section 5.1, it should be introduced, if at all, in a low-powered, reversible form and adjusted with evidence. The disclosure-only route discussed earlier in this section is the more cautious first step; the mandatory hedging obligation is a second step to be taken only if disclosure proves insufficient.

Concluding comments

310. These policies — strengthened stress-test disclosure and, if needed, flexible mandatory hedging — should be considered regardless of whether the Government proceeds with its reliability obligation proposals, because they address the financial drivers of political cost that the reliability obligation leaves untouched.

6 Concluding thoughts

311. The winter of 2024 was painful and the desire to ensure it is not repeated is entirely understandable. A responsible government could not simply ignore the distress of industrial communities or the anxiety of the wider public. The issue is whether the Minister's proposal is the right way to address those concerns. In my view, they are not.

312. The central problem the government most wants to solve — the political cost of dry-year events — is not mainly a physical problem at all. It is financial and informational. It is financial because the acute distress falls on a small number of heavily exposed industrial users, and the remedy for financial exposure is financial: securing hedge cover well in advance. It is informational because high spot prices are so easily mistaken for a failing system when they are in fact a functioning one, and because ministers are too often left without the independent, credible information they need

to resist opportunistic lobbying. Addressing these two things directly would do more to restore durable confidence than any quantity-based obligation.

313. The recommendations in section 5 follow from this. The first-best course is to wait, and watch how the other initiatives already adopted by the Government bed-in. If the government determines that it must act, it should act cautiously and reversibly: with independent checks on technical judgements, market-based cross-checks drawn from hedge prices, and an automatic expiry unless Parliament renews the rule. The short-term obligation should be dropped, or at most replaced by a simple, outcome-based scheme that leaves operational decisions with those best equipped to make them.

314. A final observation. New Zealand's electricity market has, for more than three decades, delivered security of supply outcomes far superior to the centralised system that preceded it, and it has done so while decarbonising faster than most. It is precisely at moments of stress that the temptation to reach for centralised control is strongest — and precisely at those moments that the case for preserving the market's adaptiveness is most important. The goal should be to help the market and its participants weather difficult years, not to replace their judgement with the necessarily more cautious, and more costly, judgement of a regulator.

Appendix 1: Further detail on the framework in section 2

315. The consultation paper claims conditions have changed, warranting intervention to provide assurance that security of supply will reach acceptable levels in future. However, the paper does not analyse the proposal within a realistic regulatory and policymaking framework. As a result, it does not consider potential unintended consequences and ignores important questions.

316. This appendix outlines a coherent framework encompassing public policy realities. It contrasts the standard risk management approach for dealing with uncertainty with a more conservative prudential assurance approach and discusses why policymakers can fall into the trap of preferring the latter even when it is not the appropriate approach. It also discusses competing incentives that can lead them to pursue bold one-off approaches elsewhere in the system, undermining the prudential approach. The appendix concludes with a discussion of the problems that arise when past government policies undermine investor confidence and why a prudential approach is likely to lead to ever-tightening prescription and control.

A1.1 Standard risk management vs prudential assurance approaches

317. The terms risk and uncertainty are often used interchangeably. However, in the economics literature, *risk* refers to situations where decisionmakers are comfortable with assigning probabilities to future outcomes. They may be able to use historical data to objectively estimate probabilities. Or they may be willing to form subjective probabilities and revise them as they gain experience.[44]

318. Risk is one type of uncertainty. Another is *deep uncertainty*, which refers to situations where decisionmakers cannot specify all possible outcomes and assigning probabilities is unreliable or misleading.[45] This occurs when decisionmakers are very uncertain about the system producing observed outcomes, so there are very significant 'unknown unknowns'.

In practice, there are different degrees of deep uncertainty

319. In practice, decisionmakers are never able to specify all possible outcomes, and there are always some 'unknown unknowns.' But when they believe they have a good appreciation of the spectrum of outcomes, and their approximate probability, then the standard risk management approach is good enough to tolerate its imperfections.[46]

320. On the other hand, when decisionmakers are not confident about the probabilities, they often prefer a more conservative approach, for example an approach called prudential assurance (defined immediately below). But when they have minimal confidence about the spectrum of outcomes, decisionmakers adopt approaches that avoid assigning probabilities at all. For example, they might adopt robust control strategies or the precautionary principle (defined in section A1.4).

[44] This is called Bayesian decision theory or Bayesian learning.

[45] This concept originates from Knight (1921) and is sometimes called Knightian uncertainty or radical uncertainty.

[46] For brevity, I drop the reference to "standard" when discussing the risk management approach in the remainder of the paper.

Risk management vs prudential assurance approaches

321. The *risk management approach* involves making decisions based on minimising expected cost (or maximising expected value). This involves assigning probabilities to potential outcomes and calculating the probability-weighted average. If extreme outcomes carry significant probability, they may greatly affect the expected cost. Methodologically, however, extreme outcomes are not treated any differently than any other outcome.

322. The risk management approach tries to be as accurate as possible, with no optimistic or conservative bias. In contrast, under *prudential assurance* decisionmakers adopt conservative approaches, to make prudent decisions. This often involves assigning conservative probabilities to potential adverse outcomes, especially for potentially large losses.[47]

323. Alternatively, they may use standard risk analysis to provide a baseline and then use stress tests and sensitivity analysis to determine acceptable safety margins. They seek to achieve these margins by taking precautions and establishing buffers of one sort or another, eg oil reserves.

The preferences underpinning each approach

324. The presumption underpinning the risk management approach is that decisionmakers prefer strategies that deliver the smallest average cost or the highest average value. Like a long-term investor in stocks, they're comfortable with their share portfolio suffering large losses from time to time provided they receive the maximum lifetime return when they liquidate their portfolio.

325. In contrast, the prudential approach seeks to avoid large losses, reflecting loss aversion or because such losses are irreversible, destabilising or catastrophic. The presumption is that it is preferable to adopt approaches that reduce the severity of losses, or at least the frequency of them, even if this involves paying significantly higher costs on average.

326. Prudential approaches are common in the private sector. For example, many stock investors find it prudent to place stop-loss orders on their stocks, so that they are sold immediately upon their prices falling to specified levels. Private individuals often do this because of loss aversion, but trading houses do it too to avoid the catastrophe of bankrupting their business.

A1.2 Prudential assurance vs financial protection policies

327. Section A2.1 contrasted risk management with prudential assurance — two ways of deciding how much to guard against adverse outcomes. It is also important to distinguish between guarding against an event (eg prudential assurance) and being financially protected when it strikes (eg insurance). Conflating these terms muddies policymaking.

[47] That is, they adopt the high-end of the range of probabilities they consider reasonable for each adverse outcome.

Both policies share a common feature, but they are very different approaches

328. The shared feature that invites conflation is timing: in each case a cost is borne upfront to secure a benefit that materialises later, and only if an adverse event occurs. But the two are distinct responses to risk.

329. The overlap in timing is why a prudential measure is loosely described as "buying insurance". But a policy is not insurance merely because it raises expected cost. Insurance pays out when the worst happens; prudential assurance tries to make the worst less likely or less severe in the first place — a financial transfer against a physical intervention.

330. For example, a dairy farmer worried about summer drought may invest in prudential measures, such as irrigation and silage. Farmers incur these costs when it reduces the costs from lower milk output, herd loss and destocking. They can also take out financial protection, such as a rainfall-indexed policy that pays out when precipitation falls below a defined threshold. These payouts are important because it is too costly and impractical for farmers to avoid the physical production loss from droughts.

331. The two are complementary but categorically different. A farmer who bought the rainfall policy and called it "drought-proofing" would be deceiving himself, because the paddocks would still be bare; a farmer who irrigated and thought himself indemnified against all losses would be exposed, because loss control reduces risk but never eliminates it.[48]

Which matters more depends on the nature of the harm

332. Insurance and prudential assurance differ in where they are most useful. Some adverse events do their damage less through physical harm than through extraordinarily high prices, inflicting distributional and political cost (refer §A1.3). Where that is so, tightening prudential assurance to make the event rarer or milder can matter less than improving the financial protection available to those the price spike exposes. For an interested policymaker, the right balance turns on which harm drives their political cost.[49]

A1.3 Policymakers often prefer prudential and protection approaches

333. It is useful to distinguish between policymakers (ministers and ministries) and independent regulators. The above discussion presumed both are benevolent, meaning they ignore their own interests and make decisions in the best interests of society. The rest of section A2 is based on the more realistic case where regulators and policymakers consider their own interests when making decisions on behalf of society. This is called *public choice economics*.

[48] A prudential measure that lowers the frequency or severity of losses can, of course, lower the *insurable* cost of the residual risk, and the two techniques are routinely combined. The point is that they can be complements but they are not substitutes.

[49] In some sectors, prudential measures do such a good job of countering adverse events, that there is little value gained from insurance. For example, when irrigation is cheap and effective at keeping the grass growing.

The preferences of policymakers and independent regulators

334. Ministers can suffer extreme political costs when large adverse events occur, for example they may lose elections or lose political power. Their reputation for sound political management may suffer, harming their promotion prospects or undermine their Cabinet position. It is unrealistic to assume policymakers ignore these possibilities and always act benevolently.

335. These realities mean policymakers typically prefer prudential assurance approaches over risk management. And where large adverse outcomes cannot be avoided, they often favour the provision of financial protection, such as income support (eg, unemployment and sickness benefits) or assistance with unexpected expenses.

336. It is not common for politicians to mention prudential assurance. Instead, they typically espouse resilience, which refers to a system's ability to absorb shocks, recover and return to its original state. Resilience policies often include prudential assurance measures, as prudential assurance assists resilience by reducing the frequency of destabilising or catastrophic losses, making recovery easier.[50]

337. Independent regulators often prefer a *prudential-lite* approach, where they adopt conservative risk management approaches but less conservative than elected officials. They are usually required to take a long-term perspective, and they typically have significant expertise and historical data, allowing them to formulate reasonable probability distributions, making expected-loss minimisation more tractable. Also, they are almost always staffed by people who are naturally cautious and analytical (they prefer low-risk employment).

338. Independent regulators are required to act independently, which means ignoring the political fortunes of their minister. In practice, this is tempered by the fact that serious adverse outcomes will typically put an agency's existence or independence at risk, making it risky to steadfastly apply a pure risk management approach.

Economic drivers of political costs

339. In a market economy, large and prolonged price increases for essential goods and services can create severe political costs for the incumbent minister and government, sometimes more so than physical shortages. In fact, sharp price rises can engender fear of physical shortages even when they reflect efforts to avoid shortages and are succeeding in doing so.

340. Whereas independent regulators will typically focus on whether the high prices are consistent with a competitive market and efficiency, policymakers will also be concerned about distributional effects and whether voters believe businesses are making unjustified windfall gains. The political cost depends on the circumstances and each political party's constituency.

341. Considerable economic disruption often occurs when there are large and prolonged increases in the price of production inputs or when new entrants rapidly gain market share. In workably competitive markets, some firms are usually struggling for viability,

[50] Recovering to a better state is called anti-fragility (Taleb, 2012). This refers to a system that thrives from being exposed to shocks and stresses because those forces reveal better adaptations to pursue, leading to better outcomes. Over-doing the prudential assurance approach to avoid all sizable losses may undermine anti-fragility.

so when price shocks occur, they can be pushed into financial distress. The political impact can be particularly significant when the struggling firms are large employers and/or regionally important. Concerns about de-industrialisation are particularly impactful in most countries.

342. In many countries, policymakers resist structural change and seek to smooth cyclical price effects, for example through subsidies or price controls. These types of interventions are consistent with prudential and protectionist mindsets.

There are many prudential and protection policies

343. Financial protection is often paired with prudential assurance. New Zealand governments have adopted many prudential-like and protection-oriented policies over the years, for example:

- The market for corporate control – pairing of legal requirements for corporate governance with limited liability protection for shareholders.
- Labour market – pairing of for-cause dismissal requirements with unemployment benefits.
- Insurance sector – pairing of building and planning regulations with mandatory provision of earthquake insurance for property owners (via EQC).
- Banking sector – pairing of capital adequacy rules on banks with deposit insurance for customers.[51]

344. From an economic efficiency perspective, the ideal is to adopt financial protection policies and use risk management to minimise expected costs. If the financial aspect is well designed, it tends to reduce political pressure for overly conservative risk management.

A1.4 Realistic regulatory and policymaking incentives and constraints

345. The above discussion presented a simplified view of the forces driving regulators and policymakers to adopt prudential and protection policies. In practice, they face other incentives and have imperfect information about the effectiveness of their proposed interventions.

Asymmetric information

346. For example, firms know far more about their costs, technology and conduct than any regulator, and they know that is the case and can act on it. These realities make accurate and insightful regulation difficult.[52]

347. In other words, although firms operate imperfectly and fail to optimise, there is no reason to assume regulators can do better. Simply observing that firms are not making the best of a situation is no basis for intervention, per se.

[51] Interestingly, although the government tries to protect consumers from large losses in many activities, it runs a gambling business called Lotto, where people lose a little for the opportunity to win big.

[52] Laffont & Tirole (1993) *A Theory of Incentives in Procurement and Regulation*, MIT Press, chs. 1–2.

Competing incentives

348. Policymakers often need to gain support from voters with competing views and interests. This can lead them to claim they are pursuing a strong prudential approach (eg, 'bad outcomes will never occur again') but implement something lesser .[53]

349. Competing incentives also arise when the political attractiveness of interventions does not align with their longer-term economic effectiveness. This can lead policymakers to choose bold one-off ("transformative") solutions that create a 'single point of failure,' compromising their prudential assurance objective.

Instrument uncertainty

350. Other complications arise when policymakers are over-confident about the economic effectiveness of their preferred solution or for political reasons ignore genuine uncertainty about effectiveness.[54] The upshot is that intervention occurs when it would have been better to adopt a very limited intervention or take a 'wait and see' approach.[55]

351. There are two dynamic aspects to the previous paragraph, one backward-looking and the other forward-looking.

The credible set of policies shrinks when government is the problem

352. The backward-looking aspect arises when the government makes policy mistakes and becomes a major source of uncertainty. This is particularly serious when it undermines incentives for firms to make investments to serve uncertain levels of demand. In these cases, it may not be sufficient for any current government to forswear their predecessor's policies as the firms will remain concerned that when the previous government returns to power it will revert to similar harmful policies.[56] This will be particularly the case if the harmful polices were serving a powerful constituency.

353. When 'government is the problem', policies that were previously credible are no longer credible and other policies must be considered. For example, if non-intervention is no longer credible, then the current government must intervene even if it would ordinarily resist intervention. Further, the choice of intervention must be one that is likely to be enduring across multiple types of administrations. Otherwise, it won't be credible, so it won't be effective.

354. This logic underpins capital adequacy rules on large banks, for example. These rules are imposed because policymakers recognise that the banks realise that future policymakers will bail them out if they fail, so they have incentives to make riskier

[53] Needing to attract support from both voter types (multiple principals) creates a common agency problem for the policymaker (the agent). The optimal solution in common agency situations is for the agent to provide a mixed or compromise solution that no one is entirely happy with (Dixit, 1998).

[54] North (1990) refers to *instrument rationality* to explain these situations. In essence, the economy is complex, so the informational feedback from current and previous policies is inadequate to inform policymakers about how the world operates and how it would behave under new policies.

[55] An exception to the analysis is *the precautionary principle*, which requires interventions to proceed (cautiously) even in the face of uncertainty. However, this only applies when the harm from deferring intervention is thought to be large and irreversible and the harm from intervention is not.

[56] Frontier Economics (2025) covered this problem in some detail regarding the electricity sector.

investments than they would otherwise. The rules are a second-best solution, but the first-best solution (letting banks fail) is not credible.

Prudential arrangements are susceptible to ratcheting

355. The forward-looking aspect is that, once implemented, there can be strong incentives for further intervention – a *ratcheting effect* – even when the original policy is harmful.[57] That is, if adverse outcomes occur under an existing prudential approach, the tendency is to blame officials for adopting lax processes and insufficient control. The tendency is to believe that the solution is more rigorous processes and tighter control.

[57] Policies are harmful when they fail to be effective but nevertheless distort behaviour and create administration and compliance costs. Although harmful policies can be very costly on average, they benefit some voters and firms. They can remain in place for decades if the benefits are concentrated (so those voters are motivated to support politicians that support the policy) and the costs dispersed (so they ignore the issue when voting). These considerations are well-established in the public choice literature. For comprehensive treatments, see Acemoglu & Robinson (2012, 2020).

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