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Submission on a proposed reliability obligation to manage dry-year risk

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Summary

The New Zealand Climate Foundation | Whakatere i te Āhuarangi supports stronger incentives and mechanisms to manage dry-year risk. We do not, however, support the obligations as proposed.

In short, our position is:

1. **There is no need to make rushed decisions.** Both scenario modelling and forward market prices show the system being far more in balance in 2028 than in 2024, even with very limited gas availability and flexibility. We are in better, not worse shape, largely thanks to renewables build easing the need for thermal generation.
2. **Managing dry year risk should be addressed as part of improving broader market design for a system approaching 98% renewable**. There is real risk of forcing the electricity system into higher-cost solutions if a siloed perspective is taken that does not look at interconnected market issues.
3. **The dry-year problem definition needs redefining.** The discussion document frames the problem as a need for up to 3TWh over three months of long-duration firm energy. Modelling for the Foundation shows with the current rapid build-out of renewables, the gap is substantially smaller, and that the interplay with hydro spill in average and wet years plays an important role in closing it. This modelling shows existing thermal capacity being sufficient in the short term, even with reducing gas availability and flexibility.
4. **An equal and interlinked priority should be on adequacy of the overall system: ensuring renewables build keeps up with demand growth in all years, and realising the potential of flex.** Bringing new generation forward by a single year lowers prices across both average and dry years by around $30 to $50/MWh. Delay adds the same. In addition, realising the potential of flexibility to cost-effectively substitute for peaking generation can significantly reduce system costs and investment needs. The dry-year approach in this consultation would lead to top-up thermal generation being used to compensate for any delay in build or failure to bring through cost-effective flexibility: this would result in higher market and contract prices than if the system were considered in an integrated way.
5. **The proposal's design favours fossil fuels despite claiming neutrality, disadvantaging renewing firming options (including build of renewables that are only sometimes used).** The compliance timescales and firmness requirements favour purchase of fuel to run in existing thermal plant, which steers regulated demand toward gas and coal - even though this risks a higher cost outcome than if cheaper renewables and flexibility play their maximum role. Failure to properly recognise carbon value in electricity sector decision-making exacerbates this.

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Overarching comments and relationship to the consultation questions

In addition to our answers to the questions below, we wish to provide the following overarching comments. These comments and analysis speaks most directly to the problem definition (Q1 and Q2), the need to take a first principles look at the system (Q5), and providing suggestions for additional design features to ensure a dry year solution is workable, proportionate, cost-effective, and beneficial for consumers (Q14 and Q24).

Our vision for the electricity system

Upgrading New Zealand's electricity system to deliver plentiful, affordable, secure, renewable-based electricity can lower energy bills, improve energy security, and reduce emissions. We are working toward a system that is:

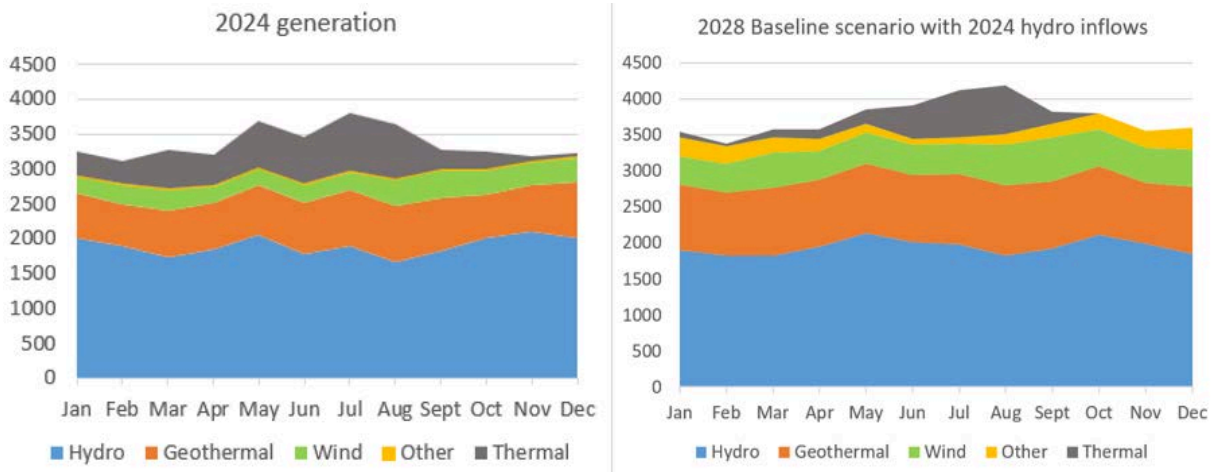
- **Plentiful:** supply is built slightly ahead of demand, so that affordable, secure supply is there to support rapid electrification.
- **Affordable:** prices fall toward the cost of new generation, and network regulation enables local distributed solutions that reduce investment cost.
- **Secure:** clean firming options cover the remaining dry-year gap after renewables build is maximised, breaking the link between electricity prices and volatile fossil fuel prices.
- **Renewable:** reaching 98% renewable generation by 2030, which modelling shows is the most cost-effective path.
- **Climate-aligned:** build and dispatch decisions properly value emissions, and affordable, reliable electricity underpins cost-effective electrification across the economy.

We wish to make overarching points on the proposed dry year reliability obligation proposal and the questions asked in the discussion document.

1. There is no need to make rushed decisions.

Both scenario modelling and forward market prices project the system to be in better balance in 2028 than it was in 2024, even with falling gas availability and less flexibility. We are in better, not worse shape, largely thanks to rapid renewables build easing the need for thermal generation overall. Modelling commissioned by the Foundation from Energy Link demonstrates this (Figure 1).

Figure 1: Monthly generation in 2024, and modelled[1] for 2028 with 2024 inflows



It is immediately apparent from Figure 1 that the need for thermal generation is reduced, even for the same hydro inflows. This is because the strong need for thermal in 2024 was largely not due to it being a dry year; it was because overall supply and demand were out of balance and thermal generation provided costly cover for a lack of renewables. Rapid renewables build means that this will no longer be the case in 2028 and beyond, as long as renewables build keeps up with demand growth.

Figure 2 shows modelled thermal generation over eight months from January to the end of winter, showing both the average across all hydro years and for 2024 inflows. The need for thermal generation is halved compared to 2024 because renewables now supply the every-year generation that thermal was compensating for in 2024. The incremental "dry year" extra thermal is small, because 2024 inflows were actually not particularly dry. The huge drop in thermal requirement since 2024 emphasises the importance of renewable supply keeping up with demand.

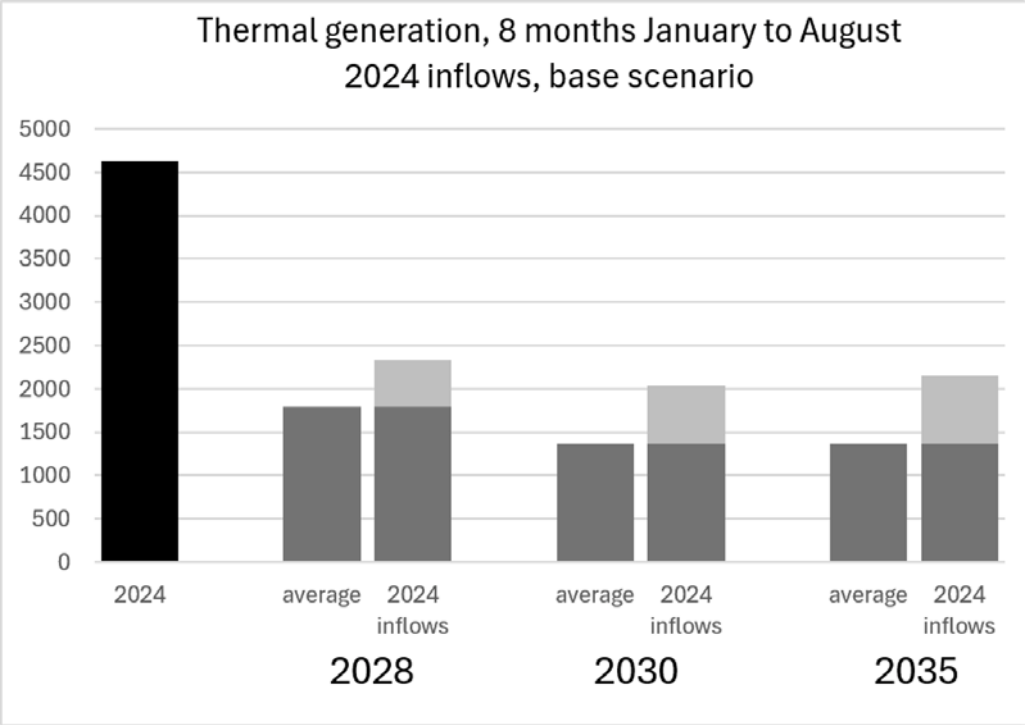
Independent scenario modelling reaches the same conclusion. Concept Consulting's *Outlook for the New Zealand Gas Market* finds that even in a stretched scenario with low gas production, high demand and no new gas storage, there is no shortfall that would require LNG before 2030.

Given that 2024 was not a particularly dry year, we will use 2012 inflows as a representative dry year in the remainder of this submission. Generation from January to August (rather than only for three months over winter) is shown, because generation in the leadup to winter allows lakes to be held higher, which is just as important as top-up generation during winter and allows better use of existing assets.

If there is nonetheless residual concern about near-term security, the least-cost rapid response is to accelerate embedded solar and batteries rather than to force procurement of thermal fuel, with dual-fuel capability at existing gas peakers as a prudent low-cost backstop. Measures that give investors confidence to build ahead of demand will increase security and affordability.

[1] Energylink medium demand growth scenario; with nominal carbon price in 2030 of $109/t and gas price $21/GJ.

Figure 2: Generation January to August in 2024 and future years. Extra thermal required in a "dry year" equivalent to 2024 (vs average of all years) is shown in light grey.



2. **Managing dry year risk should be addressed as part of improving broader market design for a system approaching 98% renewable. Dry year risk should be considered as part of a first principles review of the whole system, not considered in isolation.**

The New Zealand Climate Foundation supports stronger incentives to manage dry-year risk. We do not, however, support the obligation as proposed. A proposed dry-year solution should be considered as part of considering the wider electricity system and its market design, as the dry-year risk is interconnected with wider issues. There is real risk of forcing the electricity system into higher-cost solutions if a narrow perspective is taken that does not look at interconnected market issues.

The current electricity system incentivises just in time build of electricity generation, does not adequately value carbon, and is designed for a traditional centralised system at a time of global transformation to more renewable, distributed electricity systems.

We support a review of the electricity system that considers a broader set of challenges with the current system, focusing on a vision of plentiful, low emissions, and affordable reliable electricity that enables rapid electrification.

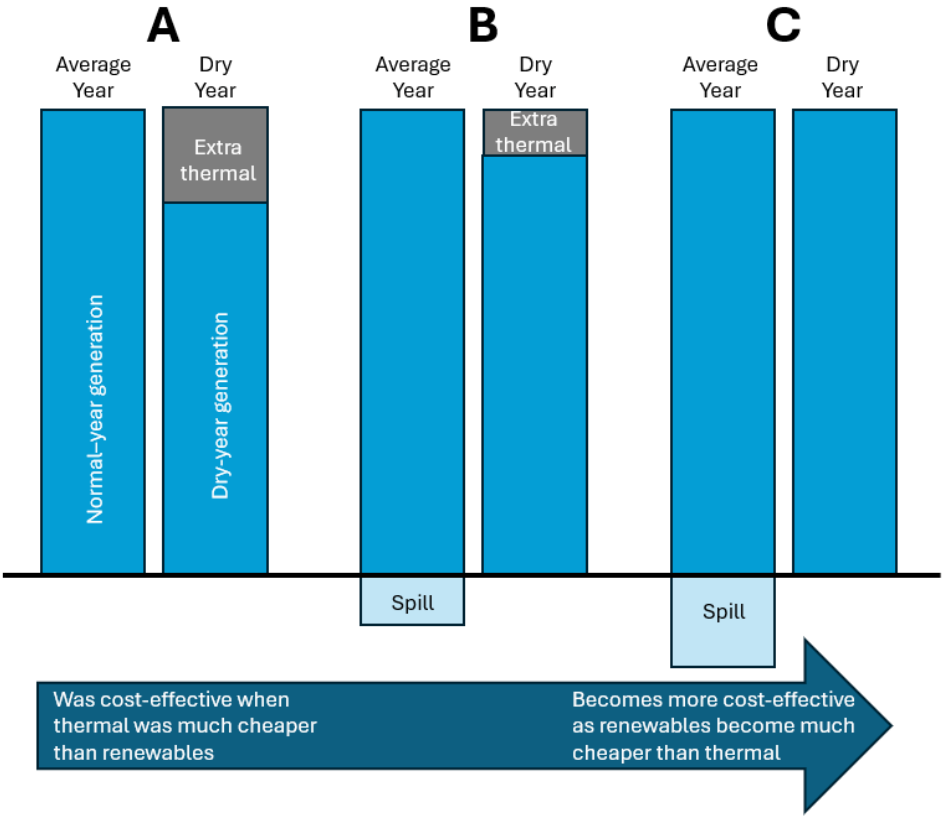
3. The dry-year problem definition needs redefining

The discussion document builds its case on a figure of up to 3TWh of long-duration firm energy needed to "fill the gap" in a significant three-month dry period. That figure predates the effect of the last two years of renewables build, and the evidence no longer supports it. The rapid build of renewables has shrunk the need for thermal generation, because a larger renewable fleet supplies more energy in all years, including dry ones.

As renewables become increasingly cheap, the economics of cost-effective dry-year response change. In the past when renewables were expensive, it made sense to use thermal to "fill the gap" when hydro inflows were low. This is the framing used in the discussion document, and is illustrated as "A" in Figure 3 below.

However as renewables rapidly become cheaper, the economics change: it makes sense to build more, and have excess in an average or wet year - resulting in undispatched renewable generation and/or hydro spill. This is shown as "B" in FIgure 3, and is the state of our current system. In a dry year, there is much less spill, as water is conserved and use of renewables maximised - that extra generation means that less thermal is needed to manage the same dry-year shortfall. Accordingly, our view is that undispatched renewable generation and spill are system security assets, just like backup thermal plant. Any dry-year market solution should drive renewables build up to its cost-effective potential : failure to do so will result in a higher-cost thermal solution being used.

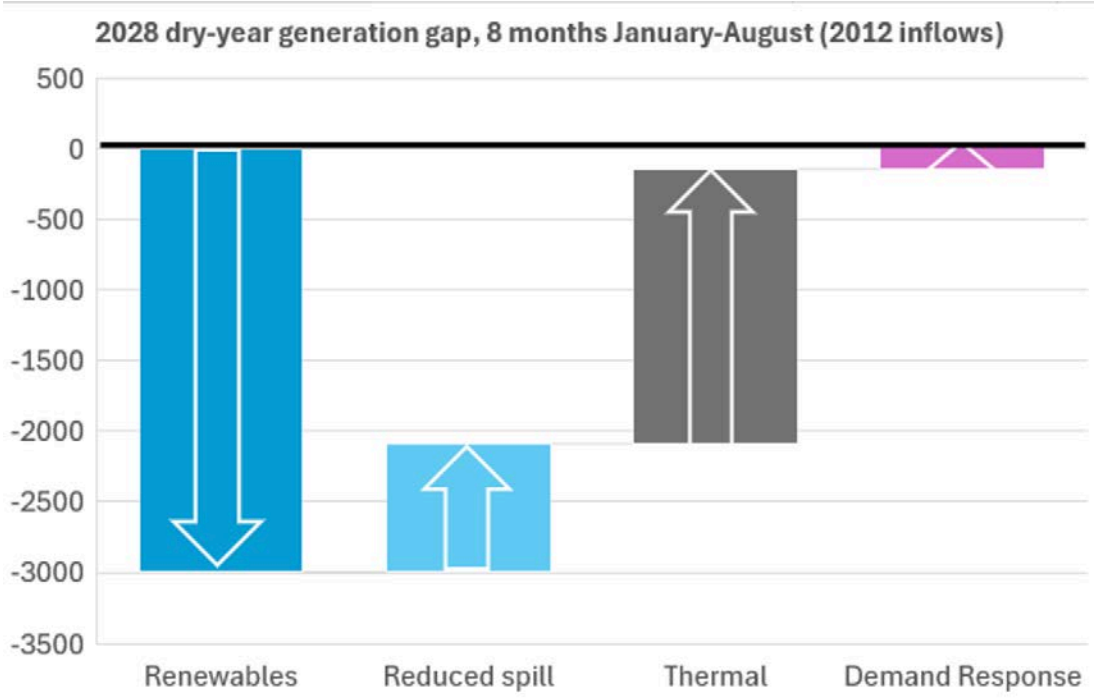
Figure 3: As renewables get cheaper, it becomes a more cost-effective dry-year solution to build plentiful renewables and allow spill in average and wet years than to "top up" supply with thermal in a dry year. Spill and undispatched renewables should be considered a security asset.



In Figure 3, “C” shows a hypothetical future where renewables are sufficiently cheap that no thermal top-up is required to cover the dry year gap. Dispatchable generation and flexibility (from grid and household batteries, demand response, low-carbon peaking and firming generation including biomass and geothermal) will still be an integral part of balancing the system every year. And in reality, rather than “surplus” renewables being unused, there will likely be innovative buyers who are willing to contract for extremely cheap electricity only when it is surplus. This would further accelerate the move from “A” toward “C” on an economic basis.

This dynamic is illustrated in the Energy Link scenario modelling. Figure 4 shows the modelled difference in generation in 2028 between an average across all hydro years, and with 2012 dry-year inflows, in the same baseline scenario as Figure 2. With dry-year inflows, there is around 3000GWh less renewable potential over eight months. The scenario meets demand partly with extra thermal (just under 2000GWh over eight months), but also through nearly 1000GWh of reduced spill: renewables that would have been unused in an average year are available to contribute in a dry year. A small component of demand response covers the remainder.

Figure 4: With 2012 inflows there is a 3000GWh reduction in renewable generation potential across eight months. This is covered through a combination of reduced spill demand response, and thermal generation.



The discussion document overlooks the potential for extra renewable generation in a dry year due to reduced spill. This is a significant factor in reducing the need for thermal in a dry year to easily manageable levels: the 2000GWh in this scenario could easily be delivered by existing assets over eight months.

Options that give cheaper system outcomes should not be discarded because they do not match commercial investment incentives under current wholesale market structure. This is a consultation on market options: it should start with identifying the lowest-cost system, then consider what market changes may be needed to provide the investment and operational incentives to deliver it. If the solution-space is artificially constrained to take cheaper options off the table, the result will be a higher-priced electricity system.

The problem definition is important because the scale of the assumed problem drives every downstream design choice: the size of any obligation, the penalties attached, and the fuel that can plausibly meet it. If the true near-term gap is a fraction of 3TWh over three months and is manageable with existing firming, the case for a far-reaching obligation that draws new fuel into the system is correspondingly weaker. We recommend the obligation be sized against current modelling of the residual gap after renewables build. We also recommend that any new market mechanism is designed to maximise the cost-effective contribution of further renewables build.

The solution to the dry year should also be in the context of climate change and affordability challenges. Carbon should be better valued, and the most important outcome is an electricity system that is secure and affordable, giving confidence to underpin electrification decisions.

4. **An equal and interlinked priority should be on adequacy of the overall system: ensuring renewables build keeps up with demand growth in all years, and realising the potential of flex.**

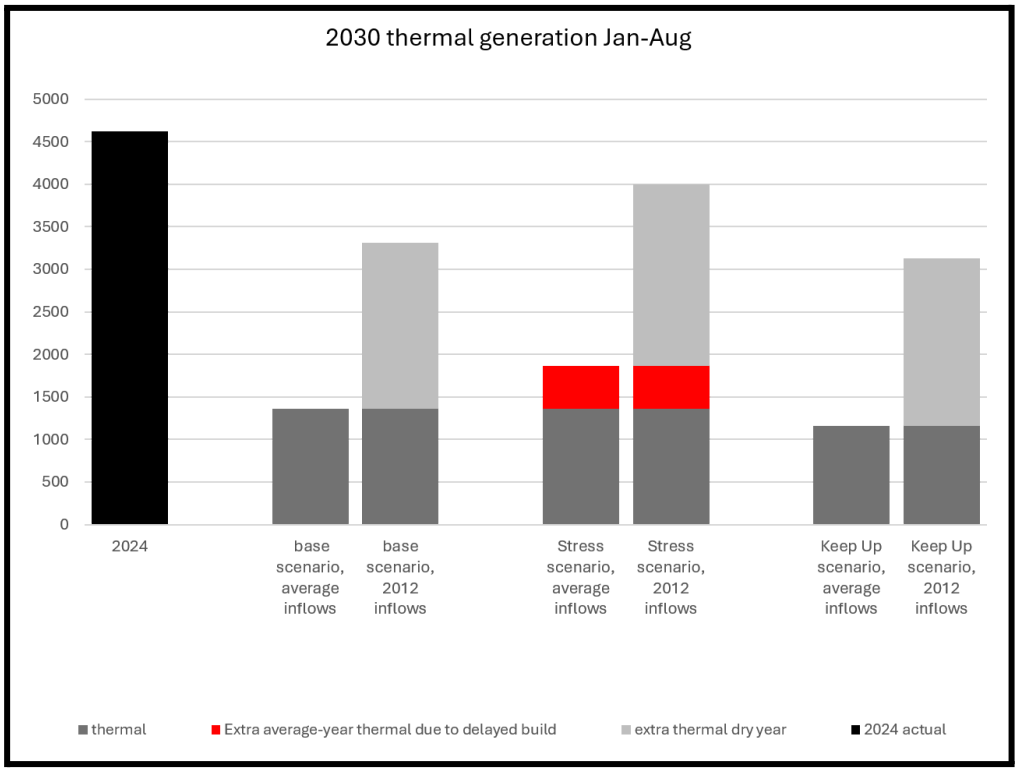
Dry-year policy is closely interconnected with the wider electricity system. To deliver secure supply at lower prices, a systems approach is needed, including keeping renewables build on track to keep up with (uncertain) demand growth under uncertainty, and maximising the role of flexibility to avoid costly peaking generation. Dry-year solutions interact strongly with these: if considered in a siloed way, a more expensive outcome overall is likely.

Bringing renewable supply forward to create more of a buffer in the system lowers wholesale market prices. As noted above in relation to 2024 generation, if a mismatch develops between overall supply and demand, this creates an additional draw of fossil fuel generation, and significantly pushes up prices.

Energy Link modelling for the Foundation shows that bringing generation forward by just one year reduces wholesale prices across both average and dry years by around $30 to $50/MWh. A delay of a single year adds $30 to $50/MWh.

Figure 5 shows thermal generation (again, Energy Link modelling) in 2030 in the same baseline scenario as previous graphs, a “stress” scenario that has higher demand growth and generation not fully keeping up, and a “Keep up” scenario that advances generation build by one year compared to the stress scenario. For each, the extra thermal generation across eight months in the 2012 representative dry year is around 2000GWh; able to be covered by existing fuels and assets.

Figure 5: With 2012 dry-year inflows, there is around 2000GWh of extra thermal generation needed over 8 months (light grey). If renewables build does not keep up with demand (Stress scenario), extra thermal (red) is required, raising average wholesale prices. Bringing generation forward by a year (Keep Up scenario) returns the requirement for thermal to baseline levels, returning wholesale prices to baseline levels.



In the "Stress" scenario, delayed renewables investment results in additional thermal generation (red) having to cover the shortfall in renewables build. This reliance on thermal leads to higher wholesale prices: $30/MWh higher in the Stress scenario than the baseline, and this would be expected to be reflected in contract prices. If instead market arrangements are put in place to advance renewables build (the "Keep Up" scenario), the resulting average wholesale market price is lower - $40/MWh lower than the Stress scenario, bringing prices back to the level of the baseline scenario.

The dry-year policy proposed in the discussion document could lead to the "Stress" outcome, with any delay in investment being compensated by expensive thermal generation. This would be a costly outcome that over-builds thermal, raising prices for consumers compared with a response that looks across the whole system.

In addition, dry-year policy will interact with flexibility policy. If demand response and storage (including smart EV charging and use of EV batteries for V2G) are properly brought into the system, the need for expensive thermal peaking will reduce. With lower reliance on thermal, the relative economics of fossil solutions for dry-year use changes. Again, siloed thinking will likely lead to higher-cost outcomes.

5. **The proposal's design favours fossil fuels despite claiming neutrality, disadvantaging renewing firming options (including build of renewables that are only sometimes used).**

The discussion document states that the obligation is technology- and fuel-neutral, and that the critical question is not the form the response takes. We agree with that principle. In practice, however, the design does not deliver it.

The short-term obligation gives generators a four-week response window to secure genuinely firm fuel cover once triggered. The firmness tests, and the document's own worked examples, point to one realistic form of compliance on that timescale: ordering fossil fuels. A generator cannot build a battery, commission long-duration storage, or sign a long renewable power purchase agreement inside four weeks. The effect is that a mechanism described as neutral structurally rewards holding gas or coal, and treats stored water and new clean resources as harder to count. Similarly the long-term obligation is only triggered in the case of shortage, favouring use of fossil fuels in existing generating plant rather than system-level responses.

Read alongside the assumed LNG procurement in Action 1.1, the obligation appears to manufacture regulated demand for LNG-backed generation and provides the offtake the LNG terminal needs - when a broader system lens would provide dry year solutions at lower cost.

We also note that construction of the LNG terminal is far from certain, yet the current consultation seems to assume it as the default solution. There are serious questions around safety and maritime navigation that could delay or stall the project, even if the government legislates consents. And with enabling legislation now delayed until post-election, there is no guarantee that consents or a funding model for the project would be agreed. It is irresponsible in the face of this uncertainty to design security policy around the assumption that LNG will be in place.

The obligation as proposed also appears to require gentailers (and in turn their customer base) to cover dry-year backup for the significant quantity of electricity that large users buy from the spot market. Any mechanism that uses contracts as a basis of ensuring adequate supply must include all major users and retailers, so that costs are not shifted from industry onto small consumers. A contracting mechanism would also be more effective and efficient as a continuous long-term obligation for all users to hold contracts, and for contracted supply to be able to be delivered. This would be more aligned with bringing forward the necessary long-term system investment than a reactive policy that attempts only to fill gaps if they occur.

In addition, the electricity market does not value carbon at the true cost to society, and this further disadvantages renewable firming options.

A key reason the market has not delivered renewable firming is that the carbon externality of gas and coal is not properly priced. Emissions from fossil fuels cause climate damage well in excess of current NZ ETS prices. When the price signal is weak, thermal firming looks cheaper than it truly is, and lower-carbon options are held back. This also affects the economic choice explained in Figure 3: with carbon valued at closer to true costs, a renewables-spill solution would be even more cost effective.

At the full, unsubsidised cost of imported LNG, in the order of $35/GJ or more, low-carbon firming and fuel-switching options are already competitive or cheaper: biomass and electric heat in industry, and black pellets at Huntly. Under a market approach, gas users would rationally switch to these. If delivered LNG is instead subsidised to around $20/GJ, a gap of roughly $15/GJ, those alternatives are locked out and the incentive is for inefficient over-use of gas.

The obligation, by steering demand toward subsidised gas, suppresses the price signal that would let biomass, electrification and other clean firming compete on merit. We recommend two things: value carbon properly through a credible, well-signalled rising ETS price path above the current auction floor; and ensure that any LNG enters the market at full cost.

A rising ETS price path, if well signalled, need not raise electricity prices over time, because the shrinking share of fossil generation affects the wholesale price less and less as renewables grow.

The New Zealand Climate Foundation is an independent, non-partisan, philanthropically funded organisation focused on achieving material emissions reductions through evidence, collaboration and systems change.

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Questions for the consultation

Q1. Do you agree with the analysis in this chapter of why New Zealand does not currently have sufficient dry-year firming? If not, where do you disagree?

☐ Yes ☒ Yes, with changes ☐ No

Please explain your views.

We agree there is a dry-year risk worth managing, but only with significant changes, above all how the scale of the problem is framed. The discussion document's case rests on a need for up to 3TWh of long-duration firm energy over a three month dry period, a figure that predates the last two years of renewables build. Modelling for the Foundation by Energy Link shows the dry-year gap is now substantially smaller, because a larger renewable fleet supplies more energy in all years and reduced spill in dry years contributes further. Existing thermal capacity is sufficient in the near term even with reduced gas availability, and independent modelling by Concept Consulting finds no shortfall that would require LNG before 2030. The problem should also be defined to include emissions and affordability, not reliability alone. We consider the problem is materially overstated and should be redefined and resized against current modelling of the residual gap after renewables build.

Q2. What do you consider to be the principal remaining barriers to investment in additional dry-year firming following the recent reforms to improve fuel adequacy (Government procurement of an LNG importation facility)?

Please explain your views.

The framing of barriers to dry-year firming is itself part of the problem, because it treats the question in isolation from wider market design. The principal barriers to a cost-effective, low-emissions response are: a wholesale market that does not value carbon at anything near its true cost, so fossil firming looks cheaper than it is and lower-carbon options are held back; a market structure that incentivises just-in-time build and does not treat undispatched renewables and hydro spill as the system security assets they are; and a failure to bring flexibility (demand response, batteries, smart EV charging and vehicle-to-grid) fully into the system. We also caution that the LNG import facility is far from certain, with safety, consenting and funding questions unresolved and enabling legislation delayed until after the election, so it should not be assumed as the default backstop.

Q3. Do you agree that, despite the recent reforms to improve fuel adequacy, information, roles and tools, further measures are still needed to strengthen incentives to invest in dry-year firming? If not, please explain why not?

☐ Yes, I agree ☒ I agree in part ☐ No, I don't agree

Please explain your views.

We agree that stronger incentives and mechanisms to manage dry-year risk are worth pursuing, but not in the form proposed. Dry-year risk is interconnected with

the wider market and should be addressed as part of a first principles review of the whole system for a grid approaching 98% renewable, rather than as a siloed obligation. A narrow measure risks forcing the system into higher-cost solutions and over-building thermal.

Q4. Do you agree that there is value in building new measures on existing regulatory architecture, rather than creating an entirely new regime from first principles? Why or why not?

☐ Yes, I agree ☒ No, I don't agree

Please explain your views.

We do not agree. This is a consultation on market options, and it should start by identifying the lowest-cost system and then ask what market changes are needed to deliver it, rather than constraining the solution space to what fits the existing architecture. Building only on the current architecture risks taking cheaper, cleaner options off the table because they do not match commercial investment incentives under the current wholesale market structure, which would result in a higher-priced electricity system. We support a first principles review focused on plentiful, low-emissions, affordable and reliable electricity that enables rapid electrification.

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Long-term Obligation

Q5. Do you agree that a long-term obligation should be introduced to strengthen incentives to secure sufficient dependable winter cover in advance where a forecast winter energy adequacy shortfall is identified? If not, why not?

☐ Yes, I agree ☒ No, I don't agree

Please explain your views.

We do not support the long-term obligation as proposed, which is triggered only when a forecast shortfall is identified. A reactive mechanism that acts only to fill gaps favours running existing thermal plant on fossil fuel over system-level responses, and is poorly aligned with bringing forward the long-term investment the system actually needs. A continuous long-term obligation to back contracted supply with a demonstrable ability to deliver would be more effective and efficient, and better aligned with advancing renewables build. Any such obligation should be sized against the real residual gap after renewables build and designed to maximise the cost-effective contribution of renewables and flexibility. It should also include major users, not just retailers.

Q6. Do you agree that the long-term obligation should be placed on large wholesale purchasers rather than on, say, generators or the market more broadly? If not, which parties should hold the obligation, and why?

☐ Yes, I agree No, I don't agree

Please explain your views.

Q7. Do you agree that a de minimis threshold should apply to limit the obligation to wholesale purchasers with a material winter load? If so, is the 500 GWh threshold appropriate, and should it be measured by reference to aggregate load over the winter period?

☐ Yes, I agree I agree in part ☐ No, I don't agree

Please explain your views.

Q8. Do you agree with the proposed staged approach under which a warning notification would be issued five years out, a binding obligation would be issued three years out and compliance would be assessed one year out? If not, what timing or trigger approach would be preferable?

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

[insert response here]

Q9. Do you agree that any identified adequacy shortfall should be allocated among obligated wholesale purchasers by reference to their shares of expected winter demand? If not, what allocation approach would be preferable?

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree ☐ Not sure/no preference

Please explain your views.

[insert response here]

Q10. What forms of cover should be eligible to meet the long-term obligation?

Please explain your views.

Eligible cover should be genuinely technology-neutral, including proper valuation of carbon emissions. If the ETS remains constrained and continues to significantly under-value emissions, this tilts the playing field toward thermal solutions. To correct for this and deliver genuine neutrality, eligibility should favour low-carbon solutions. The policy should also be sure to include options that are often overlooked. In particular, undispatched renewable generation and hydro spill should be treated as system security assets in the same way as backup thermal plant, because in a dry year reduced spill makes additional renewable generation available to meet the shortfall. Above all, the mechanism should be designed to drive renewables build up to its cost-effective potential, since failure to do so results in a higher-cost thermal solution.

Q11. How should the compliance framework be designed? In particular, what evidential standard should apply, and how should the regime address more difficult issues such as hydro treatment, attribution, portfolio treatment, shared arrangements and double counting?

Please explain your views.

[insert response here]

Q12. Should the regime deal with arrangements that appear compliant in advance but later fail because of counterparty failure, project delay, force majeure or similar events? If so, how?

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree ☐ Not sure/no preference

Please explain your views.

[insert response here]

Q13. Should penalties for non-compliance be designed and calibrated to tilt investments to comply without overly encouraging inefficient over-procurement? Please explain your reasoning.

☐ Yes, I agree ☒ I agree in part ☐ No, I don't agree ☐ Not sure/no preference

Please explain your views.

We agree that any obligation and its penalties should be calibrated to avoid encouraging inefficient over-procurement. Our central concern is that the proposal as framed risks precisely this outcome: over-building thermal to compensate for delayed renewables build, or for flexibility that has not been brought through, at a much higher cost to consumers than an integrated, whole-of-system response. Penalties and obligation size should be set against the real residual gap after renewables build, and designed so that the least-cost response, including renewables, reduced spill and flexibility, is able to comply.

Q14. What other design features, transitional arrangements, or implementation issues should be considered to ensure that the long-term obligation is workable, proportionate, cost-effective, and beneficial for consumers?

Please explain your views.

The most important design features are: size the obligation against current modelling of the residual gap after renewables build, not the pre-build 3TWh estimate; design any mechanism to maximise the cost-effective contribution of further renewables build, treating undispatched renewables and spill as security assets; include all major users so costs are not shifted onto small consumers; and prefer a continuous obligation to back contracted supply over a reactive gap-filling trigger. The regime should not assume the LNG terminal will be in place, given unresolved safety, consenting and funding questions and legislation delayed until after the election. Carbon should be valued properly through a credible, well-signalled rising ETS price path above the auction floor, and any LNG should enter the market at full, unsubsidised cost, or clean alternatives should receive an equivalent offset, so the mechanism does not lock out biomass, electrification and other low-carbon firming.

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Short-term Obligation

Q15. Do you support the introduction of a short-term obligation as a targeted backstop where a near-term winter reliability risk emerges despite the operation of the long-term obligation?

☐ Yes, I agree ☒ No, I don't agree

Please explain your views.

We do not support the short-term obligation as proposed. As designed it favours fossil fuels: the short response window and firmness requirements can realistically be met only by ordering fuel to run existing thermal plant, so a mechanism described as neutral in effect steers regulated demand toward gas and coal and treats stored water and new clean resources as harder to count. A prudent, low-cost backstop such as dual-fuel capability at existing gas peakers is sensible, but that is different from an obligation whose design entrenches fossil firming and could manufacture demand for LNG that a whole-of-system approach would avoid.

Q16. Do you agree that the short-term obligation should apply to large generators whose contribution to annual energy supply exceeds a defined *de minimis* threshold? We welcome views on whether 2,500GWh of expected annual generation is the appropriate threshold.

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

[insert response here]

Q17. Do you consider the proposed trigger – projected hydro storage crossing the Watch Curve within 90 days if it declines at an assumed rate of 18GWh/day – is appropriate? If not, what alternative trigger should be considered?

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

[insert response here]

Q18. Do you agree with the proposed monitoring period, notification process, three-week response window, and approach to switching off the obligation if conditions improve? If not, what alternative process would be preferable?

☐ Yes, I agree ☒ No, I don't agree

Please explain your views.

Q19. Do you agree that each obligated generator's obligation should be determined by reference to the winter load its portfolio is expected to support, including its own retail load and relevant contractual commitments? If not, what alternative basis should be used?

☐ Yes, I agree ☐ I agree in part ☐ No, I don't agree

Please explain your views.

[insert response here]

Q20. What forms of firm energy fuel cover should qualify under the short-term obligation? In particular, how should hydro be treated, including whether, and in what circumstances, existing stored water should be capable of counting toward compliance?

Please explain your views.

Q21. How should compliance be assessed? We welcome views on what evidence should be required, and how the Authority should approach questions of firmness, attribution, double counting, and reliance on third-party arrangements (including examples of how these matters are addressed in other jurisdictions).

Please explain your views.

[insert response here]

Q22. How should the regime deal with arrangements that appear compliant in advance but fail in practice because of upstream supply failure, transport disruption, force majeure, counterparty failure, or similar events?

Please explain your views.

[insert response here]

Q23. How should penalties for non-compliance be designed and calibrated so that they provide a credible incentive to secure genuine firm fuel cover without encouraging inefficient or disproportionate responses?

Please explain your views.

[insert response here]

Q24. What other design features, transitional arrangements, or implementation issues should be considered to ensure that the short-term obligation is workable, proportionate, cost-effective, and beneficial for consumers?

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Please explain your views.

The short-term obligation should not be considered in isolation. A whole-of-system lens would deliver dry-year security at lower cost by advancing renewables build, realising flexibility, and recognising spill and undispatched renewables as security assets. The regime should not be designed around an assumption that the LNG terminal will be in place, given unresolved safety, consenting and funding questions and legislation delayed until after the election. Carbon should be valued closer to its true cost, and any LNG should enter the market at full, unsubsidised cost so that biomass, electrification and other low-carbon options are not locked out. Where residual near-term concern remains, accelerating embedded solar and batteries, with dual-fuel capability at existing gas peakers as a low-cost backstop, is preferable to forcing procurement of thermal fuel.