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To: MBIE
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Genesis Energy's submission on MBIE's proposed dry-year reliability obligation

Genesis Energy Limited **(Genesis)** welcomes the opportunity to comment on the Ministry of Business, Innovation and Employment's **(MBIE)** *A proposed reliability obligation to manage dry-year risk* consultation paper.

We support MBIE undertaking this work. While the system will continue to require thermal generation, revenue uncertainty will remain a problem and is likely to become more acute as New Zealand's system becomes more highly renewable. We therefore agree there is a problem and that addressing this may require policy change. While the HFOs are an effective industry-led response to the dry-year problem, additional future demand for this type of contracting arrangement remains untested and based on historical experience may be highly uncertain.

We agree with MBIE's intention of developing a market-led, regulation-enabled, technology and fuel-neutral approach based on updated security standards and an updated SOSA. However, it is not obvious that the dry year reliability obligation as proposed would solve the problem above by incentivising investment in or contracting for thermal generation. There is also a risk of "over-insurance", particularly from the proposed short-term Obligation, which could unnecessarily increase costs.

Regarding the SOSA, work is needed to ensure this is fit for purpose if it is to be used as the basis for regulatory intervention rather than an information tool. One important issue to address will be ensuring energy margins reflect commercially viable, contracted generation plant (both plant and fuel). For example, Unit 5 has been temporarily removed from service for the second half of 2026 (as it was during the last quarter of 2025), demonstrating how plant modelled as physically available under SOSA may nevertheless be uncontracted and un-utilised by the market. Ensuring SOSA, and any long-term obligation, account for future plant intentions (including retirement plans) will be a key issue to address.

The proposed de minimis thresholds need to be reconsidered and revised. Consistent with our reading of the Statement of Government Policy to the Electricity Authority, we agree with the best approach is one with many different wholesale participants

managing their own risks in response to efficient price signals. We see risks from adopting a narrow threshold, including moral hazard and free-rider dynamics, including a perverse incentive on non-obligated participants not to contract firming or hedge cover. The thresholds may also create incentives for gaming, risking inefficient outcomes. This risk is particularly acute under the proposed short-term obligation, which risks creating a power imbalance in respect of natural gas contract negotiations, potentially increasing gas costs.

A key design question we have relates to how the proposed obligations would impact incentives to supply firm cover to obligated participants. For example, it is unclear if the 10-year Huntly Firming Options and Huntly Strategic Energy Reserve would be counted as load for the purposes of assessing Genesis' obligations (and qualifying cover when assessing compliance by contracted counterparties).

Given the complexity of the problem identified by MBIE, careful policy design will be important. Sequencing and timing of this work would ideally enable thorough review of the security standards (which have not been reviewed since 2012) and SOSA led by MBIE, the Electricity Authority and Transpower, and working with industry. Detailed regulation design could then follow and be informed by updated security standards and SOSA, accompanied by robust cost benefit analysis to ensure the benefits of any regulation outweigh the costs. This would also minimise risks of unintended consequences.

We do not support the proposed short-term obligation. We do not agree there is any evidence of market or regulatory failure preventing participants from contracting fuel. Rather, the problem has been the rapid unexpected decline in domestic gas production. Government is progressing options to establish an LNG import terminal to address this issue of physical supply, and to impose an additional short-term obligation ahead of this would be premature. Finally, a well-designed long-term obligation may make any short-term obligation unnecessary.

In addition to our views set out here and in our answers to MBIE's consultation questions, please also see the ERGANZ submission and attached detailed technical analysis by Concept Consulting. We do not adopt every conclusion Concept reaches but consider that its analysis is useful and should be considered by MBIE. Where positions in these documents diverge, Genesis' submission should be considered to be our view.

Yours sincerely,

Privacy of natural persons

Mitchell Trezona-Lecomte
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MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Consultation submission form

The Ministry of Business, Innovation and Employment (MBIE) would like your feedback on:

A proposed reliability obligation to manage dry-year risk.

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

When completing this submission form, please provide comments and supporting explanations for your reasoning where relevant. Your feedback provides valuable information and informs decisions about the proposals.

We appreciate your time and effort taken to respond to this consultation.

Instructions

To make a submission you will need to:

1. Fill out your name, email address, phone number and organisation. If you are representing an organisation, please provide a brief description of your organisation and its aims, and ensure you have the authority to represent its views.
2. Fill out your responses to the discussion document questions. Where possible, please provide us with evidence to support your views. Examples can include references to independent research or facts and figures.
3. If your submission has any confidential information:
    i. Please state this in the email accompanying your submission, and set out clearly which parts you consider should be withheld and the grounds under the Official Information Act 1982 (Official Information Act) that you believe apply. MBIE will take such declarations into account and will consult with submitters when responding to requests under the Official Information Act.
    ii. Confidence"). Any confidential information should be clearly marked within the text of your submission (preferably as Microsoft Word comments).
    iii. Note that submissions are subject to the Official Information Act and may, therefore, be released in part or full. The Privacy Act 1993 also applies.
4. Submit your feedback:
    i. By email to *electricitymarkets@mbie.govt.nz*
    ii. By mailing your submission to:

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

Submitter information

MBIE would appreciate if you would provide some information about yourself. If you choose to provide information in the section below, it will be used to help MBIE understand how different sectors view the proposals and options for requiring and achieving minimum onshore fuel stockholding. Any information you provide will be stored securely.

Your name, email address, phone number and organisation

Name:	Mitchell Trezona-Lecomte
Email address:	Privacy of natural persons
Phone number:	
Organisation:	Genesis Energy

☐ The Privacy Act 1993 applies to submissions. Please tick the box if you do **not** wish your name or other personal information to be included in any information about submissions that MBIE may publish.

☐ MBIE may upload submissions and potentially a summary of submissions to its website, www.mbie.govt.nz. If you do **not** want your submission or a summary of your submission to be placed on either of these websites, please tick the box and type an explanation below:

I do not want my submission placed on MBIE's website because... [insert reasoning here]

Please check if your submission contains confidential information

☐ I would like my submission (or identifiable parts of my submission) to be kept confidential, and **have stated** my reasons and ground under section 9 of the Official Information Act that I believe apply, for consideration by MBIE.

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.

In addition to our views set out below (and in our cover note), please also see the ERGANZ submission and attached detailed technical analysis by Concept Consulting. We do not adopt every conclusion Concept reaches but consider that its analysis is useful and should be considered by MBIE. Where positions in these documents diverge, Genesis' submission should be considered to be our view.

Our view is that there are barriers that prevent wholesale market participants from investing in or contracting for long-duration firming generation. Genesis agrees that market settings should evolve to reflect changing conditions, and that firming and capacity signals is one area where the market could benefit from further refinement. The 10-year Huntly Firming Options (HFOs) and Huntly Security Energy Reserve demonstrate that commercial solutions can emerge, but the broader system would benefit from clearer price signals or mechanisms for recognising the value of keeping dispatchable capacity available for security of supply. Moreover, these contracting arrangements were only entered into after a period of market stress in 2024; had the factors that contributed to 2024, namely a gas shortage and dry year, occurred one year later, it may have been too late to secure this outcome because Unit 2 would have been close to its scheduled retirement in January 2026.

Revenue uncertainty for thermal generation is likely to become an increasingly acute problem for the system, as evidenced in Concept Consulting's submission (see in particular page 25). As noted in the paper, it is increasingly difficult for infrequently used firming generation, which typically has higher LRMC and SRMC than renewables (including hydro), to cover its costs in the energy-only market. However, even a very highly renewable system featuring renewable "over-build" will continue to need a minimum quantum of firm thermal generation as backup (see Figures 6 and 7 from Concept Consulting's submission). Relying on infrequent periods of very high price volatility is unlikely to be viable for prospective investors, partly as there now exists an informal "soft" cap on spot prices. That is, we have seen that market conditions like those observed during winter 2024 provoke a robust policy and regulatory response, thereby sending the message that pricing of this level is intolerable.

The risk is particularly acute when considering whether to invest in new plant, given this involves committing hundreds of millions of dollars of capital to a long-life thermal generation plant on the expectation it will recoup its costs during short periods of energy shortage every 3-5 years, despite the fact the continued availability of the Rankine units creates significant consumer benefit (per the Commerce Commission's authorisation of the HFO):[1]

- Partial consumer surplus benefit of $13.5m - $15.8m; and
- A transfer of surplus to consumers of $2.13b - $2.24b.

Moreover, the potential market for supply of such thermal plant is small. Unit commitment of thermal firming and peaking plant is also complex, requiring significant operational and institutional sophistication to manage the various fuel, workforce and spot market dynamics.

[1] https://www.comcom.govt.nz/case-register/case-register-entries/genesis-energy-limited-contact-energy-limited-meridian-energy-limited-and-mercury-nz-limited-the-gentailers/?section=documents&date=2025-11-06

Careful problem definition will be important. We recommend as a priority MBIE work with the Electricity Authority, the System Operator, and industry as relevant to review and update the security standards and SOSA. Ideally, this work would precede and inform detailed design of the proposed long-term obligation (LTO). This will be particularly important given the security standards as prescribed in Part 7 of the Code and set out in the Security Standards Assumption Document (SSAD) have not been reviewed since 2012. Reliance on the SOSA to trigger regulatory obligations mean it will be critical to ensure the SOSA is fit for that purpose. For example, we note the SOSA has historically over-estimated future demand (see Figure 6 in Concept Consulting's submission).

We take it to be an intentional design feature of MBIE's proposal that the system would err on the side of "over-supply" rather than under-supply, on the basis that any resulting long-term price impact is worth paying for the corresponding reduction in price volatility and potential for elevated prices during a dry year. The implicit assumption in MBIE's paper appears to be that the value placed on reliability (or value of lost load) should be higher than it is under current market settings, reflecting the range of broader economic and social costs that are essentially externalities from the perspective of the energy-only market (for example, reductions to demand which have broader economic and social impacts). In this sense, the proposal could be seen as a mechanism for addressing potential externalities of inadequate resource adequacy. While we understand the rationale, it is worth pointing out that the costs and benefits of such an approach should be thoroughly identified and quantified (within reason) before any obligation is introduced, to ensure benefits to New Zealand and consumers outweigh costs. As noted in Concept Consulting's report, the risk of "over-insurance" resulting in higher prices is greatest from the proposed STO.

We are not convinced there is a problem requiring introduction of a proposed STO focused on months-ahead fuel adequacy. We are not convinced there are barriers preventing market participants from investing in additional fuel over the short-term (in-year), particularly if the Government progresses with an LNG import terminal. Wholesale market participants already have strong commercial incentives under the spot market to ensure they have sufficient fuel to cover their contractual obligations and to use fuel efficiently. This has been observed in practice in time and again when dry sequences emerge. A key issue we see with the proposed LTO and STO is they risk creating a perverse incentive *not* to contract by non-obligated participants. This is because they know that the system risk has been covered by obligated participants and therefore the risk of high prices due to scarcity is lower. In practice, this will expose these participants to the risk of high prices occurring due to things the winter energy reliability obligation can't capture (asset or supply chain failure etc.). It is precisely these unexpected circumstances that impacted upon spot-exposed firms in 2024.

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.

As noted above, we think the key barriers can be summarised as follows:

- **Uncertainty of commercial return on long-life, high-capital thermal firming plant**. This is a function both of market design (energy-only market) and demand uncertainty. As noted, market design makes it difficult for infrequently used higher LRMC/SRMC firming plant to cover its costs. We also note that while adding LNG will improve fuel availability, it does not solve bankable revenue for firming and peaking capacity.
- **Under-priced or under-valued externalities**. It may be that the economic or social cost or value placed on energy security is not fully reflected within the energy-only market. As has been observed, this may be because of an informal or soft cap (social or political

constraint) on spot prices which prevents energy market price discovery of the value of lost load.

- **Mismatched incentives**. As noted by MBIE, there is a tenor gap between the contract duration buyers of firmed electricity are generally willing to commit to and the lifespan of thermal firming plant. It is unclear to us if the proposed LTO will address this barrier.
- **Demand uncertainty**. Demand in New Zealand has been flat around 40TWh for the past ~20 years. Recent uncertainty over the future of large electricity users, particularly the aluminium smelter at Tiwai, exacerbated this risk materially. Observed demand growth has consistently fallen short of forecasts including those in the SOSA.
- **Supply growth**. New Zealand is in a renewables boom. As more renewables enter the system, aggregate demand for thermal firming generation will decrease (as evidenced in Concept's report), particularly as hydro is able to perform more of a peaking and firming role, when water is available.
- **Policy uncertainty**. For example, it was recently government policy to seek an aspirational target of 100% renewable electricity. As recently as 2023 the Government was investigating a ban on new baseload thermal generation[2]. One of the options in the New Zealand Battery Project included very large hydro storage at Lake Onslow, which also would have materially changed demand for firming generation. Given thermal firming plant is long-lived and high capex the possibility of significant policy changes under future Governments is a material risk.
- **Environmental, Social, and Governance (ESG) considerations restricting access to capital**. Many global, and some domestic, institutional investors impose a premium on capital for thermal generation plant or restrict it entirely, raising the cost of capital. It is also worth noting here that government is working with the Centre for Sustainable Finance to develop an "Aotearoa New Zealand Sustainable Finance Taxonomy" for the energy sector. The taxonomy is "...intended to enable financial market participants to more easily identify environmentally sustainable investment opportunities, mitigate greenwashing risks, reducing friction and cost, and support capital allocation decisions that can enable New Zealand's sustainable future". We note it will be important to ensure this taxonomy, and any other government policy or regulatory settings that influence capital allocation within New Zealand, are aligned to the objectives of MBIE's proposed LTO and/or STO.

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.

Yes. See our response to question 1 and 2 above. We agree there is a case for regulatory change to solve the problem as stated above relating to incentives for dry-year firming. The key problem is revenue certainty and adequacy for thermal plant needed by the system. This problem is likely to become more acute as the system becomes more highly renewable. Consistent with the ERGANZ submission, we would support MBIE undertaking work on a forward-looking assessment of adequacy.

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?

[2] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/electricity-transition/implementing-a-ban-on-new-fossil-fuel-baseload-electricity-generation

☒ Yes, I agree ☐ No, I don't agree

Please explain your views.

Yes, given our understanding of the problem: we view the problem as relatively narrow and therefore a targeted regulatory response may be appropriate. We agree with MBIE's proposed approach to build on revised security standards and SOSA and existing market regulations.

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 agree there is a problem the solution to which likely requires regulatory change in some form. We agree some type of LTO may be the best approach, insofar as it remains consistent with a market-led approach. We support MBIE progressing this option to a detailed design phase, allowing time to review and update the security standards and SOSA as inputs to regulatory design.

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.

It probably makes sense for the obligation to be based on load rather than generation, but we would like to see this proposition more rigorously tested. If the obligation is to be based on load, we suggest the obligation be

- based on net load rather than gross load, to avoid dis-incentivising demand growth and to incentivise obligated participants to continue growing generation supply to offset their potential exposure. See further detail below under question 8.
- based on annual rather than winter-only load, to avoid gaming. See further detail below under question 10.
- assessed for its likely ongoing effectiveness in a scenario where there are no longer vertically integrated electricity firms, noting that this is a policy objective of some political parties.

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.

We do not agree that the regulatory obligation should be applied based on an arguably arbitrary point-in-time assessment of different wholesale market participants' abilities to materially affect

system reliability. Consistent with our reading of the Statement of Government Policy to the Electricity Authority, we agree that an efficient electricity system is best achieved by an efficient wholesale market with "...many different wholesale buyers and sellers of electricity, managing their own risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors". As per paragraph 19 of the GPS, we agree that individual wholesale participants are best placed to understand and manage their risks, in response to efficient price signals, and how best to insure against those risks for their circumstances.[3] As is recognised in the paper, the "actions affecting long-duration firm energy are distributed across the system". It appears that a decision has been made as to which participants should be subject to the obligation (in practice the four large vertically integrated electricity generators and the smelter), and the trigger level has been set to capture these participants.

However, we agree some type of de minimis threshold will be needed. We recommend this be construed in the broadest possible terms (consistent with our reading of the GPS) to ensure benefits and costs of maintaining systemwide security are fairly and efficiently distributed across the system. Not only will this rationalise alignment between incentives and benefits/costs, it will avoid or minimise unintended consequences of a too-narrow threshold:

- **Moral hazard and the free-rider problem**. As MBIE acknowledges, imposing the LTO on a narrow subset of wholesale market participants risks giving rise to a free-rider dynamic whereby non-obligated participants may exacerbate the problem of under-investment in long-duration firming as they will not bear the costs of this problem and can benefit freely from investment by other participants. This problem is recognised in paragraph 21 of the GPS, which notes the Government will not step in to insulate wholesale participants from risk, and to do so would only increase the risk of shortage and create a "vicious circle" by undermining incentives on participants to manage their own risks properly, "chilling hedging and new investment leading to increase scarcity, more periods of high prices and reduced security".
- **Market power and commercial prejudice**. For example, should any updated SOSA threshold be triggered, the ability of obligated participants to negotiate for plant or fuel with non-obligated participants could be materially hindered, as non-obligated counterparties would know the "clock is ticking" for obligated participants, potentially raising costs for both participants and therefore end-users. This issue may be particularly acute vis-à-vis fuel suppliers who are outside the electricity market; if they know an obligated electricity participant *has* to contract within a finite time window, upward pressure on fuel prices is inevitable. While this dynamic cannot be eliminated, it would be materially mitigated by broadening the de minimis threshold.
- **Rationalisation of de minimis threshold with ability to address the problem**. A related point is that the proposed de minimis threshold effectively pre-determines market solutions to future firming needs i.e. assumes the solution must come from either one of the four current gentailers and/or NZAS. However, it is feasible other wholesale market participants may be able and willing to provide a solution.
- **Unintended consequence – interaction with Non-Discrimination Obligations**. Competition issues should be considered in the context of the Government's Energy Competition Taskforce and the new Non-Discrimination Obligations, the purpose of which is to achieve a level playing field and increase liquidity in the hedge market. A narrowly defined de minimis threshold cuts against that overarching intention. It could do this by reducing incentives for obligated participants to supply hedge contracts; if an LTO is introduced, we expect this regulation would constitute an acceptable type of "intolerable risk" for the purposes of the NDOs.

[3] Statement of Government Policy to the Electricity Authority Under Section 17 of the Electricity Industry Act 2010: New Zealand Electricity Industry - 2026-go3093 | New Zealand Gazette

- **Unintended consequence – incentives to reduce demand**. As noted in the paper, one relatively straightforward means by which an obligated participant may choose to reduce compliance exposure with any LTO would be to reduce contracted demand rather than increasing supply. If penalties are indeed set high enough to influence investment decision-making, then they will likely also be high enough to at least incentivise demand reduction. Such a dynamic would not resolve the problem MBIE has identified, particularly if all obligated participants decided to respond to the LTO in this way ie if, instead of increasing supply, obligated participants each reduced demand, thereby reducing their shortfall allocation without however any increase to systemwide firm generation capacity would not increase and the problem would remain. Broadening the de minimis
- **Regulatory durability and future-proofing**. Another issue to consider is that the threshold should ideally be durable. A narrow de minimis threshold is at greater risk of becoming outdated if market composition changes over time ie if gentailers materially reduce their demand position or seek to sell their retail book outright, or if independent retailers or generators capture greater market share. A related point is that the regime needs to be able to accommodate large new entrants to the wholesale market, for example data centres.
- **Unintended consequence – potential for gaming**. Another issue is with the proposal to define the de minimis in terms of aggregate load over winter (1 April to 30 September). Firstly, this could incentivise gaming ie obligated participants may seek to shape their load profile to minimise winter load exposure. This may prove purely hypothetical, but it is worth flagging.

We suggest a de minimis threshold that excludes very small wholesale market participants (for example, small social retailers) would be appropriate, consistent with the rationale articulated by MBIE in the paper.

One alternative option for addressing this issue may be a washup mechanism for wholesale participants not captured directly by the obligation. For example, the EA could charge a levy covering the winter energy margin and tender the volume to anyone able to cover the position. Wholesale participants could also be given the option to opt into the LTO if they wanted to cover their own position.

Another alternative would be to adopt the threshold used for the stress testing regime, given the purpose of the stress testing regime is aligned (albeit not identical) to the objectives of the LTO. As per the updated Government Policy Statement, we note the stress testing regime has a key role in promoting good risk management by wholesale participants.

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.

We agree it will be important to ensure any LTO has obligation triggers that occur early enough to give market participants time to respond. While we understand the rationale behind the proposed 5-3-1 year phasing, it may prove practically difficult to implement. For example, if a winter energy shortfall first emerges 3 years ahead but not 5 years ahead, it is unclear what would happen ie if the 2026 SOSA identifies a shortfall in June 2029 (3 years ahead) that had not been visible in June 2024, it is unclear that a LTO would have been triggered. It will be important to ensure any LTO translates into clear actionable regulatory obligations. One issue with the proposed 5-3-1 year approach is it may not provide the basis for sufficient clear signals to invest in or contract for firm plant. For example, Transpower's latest 2026 SOSA shows a NZWEM shortfall forming by 2031

under its Reference case (5 years ahead). However, in practice, it would be difficult for Genesis to make commercial decisions around future thermal plant on this basis alone. This is partly because the shortfall is contingent on development of generation projects captured in the SOSA Supply pipeline (see Table 4 in the 2026 SOSA). The shortfall could either widen or disappear depending on development of these projects. Committing capital to new or existing plant on the basis of possibly transient WEM shortfalls alone would therefore be highly risky.

As noted, one critical change to the SOSA that would be needed to enable any LTO would be to ensure the NZ-WEM reflects contracted or commercially viable capacity and energy (both plant and fuel), rather than assumptions based on physically existing plant under the System Operator's current "thermal fuel validation methodology". This would ensure the WEM reflects commercially viable plant and contracted energy. Without this change, the LTO may suffer from a "chicken-and-egg" dynamic whereby owners of thermal plant (such as Genesis) are forced to try and make credible signals about future plant intentions (including retirement) in order to "force" an LTO-trigger and thereby catalyse an appropriate response by obligated market participants. An example of this issue can be illustrated by Unit 5, which has effectively been removed from service since the second half of 2026 calendar year, as it was for the last quarter of CY25.[4] This demonstrates how physically available plant can differ materially from commercially available plant. It therefore appears difficult and unlikely any LTO will be triggered under the current SOSA methodology and security standards (per Part 7.3), and there is a risk adding a new LTO onto the current SOSA methodology will only add compliance risk (and therefore cost) into the system without solving this fundamental uncertainty.

We think there is merit in MBIE exploring an "always-on" long-term obligation. The rationale behind this would be to incentivise obligated participants to avoid the threshold ever being breached by maintaining sufficient firm generation capacity. Such an obligation would, however, require the SOSA regime to be reviewed and updated. It would likely require some level of materiality "buffer" built in for drops below the winter energy margin threshold to be defined by MBIE, the Authority, and Transpower as part of a review of the security standards and SOSA framework. That is, only shortfalls beyond a certain minimum level of materiality would trigger the 1-year response period (the response period would also need to be considered in the context of any always-on obligation). It would also require more frequent SOSA reporting by Transpower, perhaps quarterly, to keep the market informed.

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.

In principle this could work, provided the de minimis threshold is reduced as noted above to ensure allocation is rationalised across the wider market.

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

Please explain your views.

In principle, the regulatory obligation should be fuel and technology-neutral, enabling market participants to identify the best solutions, provided these are dispatchable and storable. All types

[4] https://www.genesisenergy.co.nz/about/news/genesis-to-shut-down-unit-5-to-support-gas-consumers

of generation and contracted demand response should be permissible. This supports an obligation based on net aggregate load rather than gross aggregate load which we argue better rationalises the link between the cause of the problem, allocation of compliance exposure to deal with the problem, and therefore incentives to solve the problem. We recommend allocating energy margin shortfalls on the basis of net load for the following reasons:

- Allocation based on gross load may "artificially" or inefficiently disincentivise demand growth among obligated participants. Whereas allocation based on net load allows participants flexibility to manage their demand-side and supply-side position and to reduce compliance exposure by balancing the two.
- Allocation based on net load maintains incentives on obligated participants to grow supply even *before* any winter energy margin threshold is crossed and a LTO is triggered. That is, one way to think about how any LTO should work if successful is that, if it works effectively, the obligation itself will never be triggered but will nonetheless incentivise system-wide retention of a sufficient level of long-duration firming generation. Allocating exposure based on net load achieves this by incentivising obligated participants to keep supply and demand in balance. Arguably, this would also be consistent with a fuel and technology neutral approach: obligated participants can reduce their exposure by growing renewables or geothermal, and/or optimising use of hydro within their portfolios, while simultaneously reducing the probability of the threshold being crossed.

To ensure consistency, we recommend the System Operator publish common capacity factors across generation types and that participants be required to adopt these to ensure alignment to calculation of energy margins per the SOSA.

LTO design will also need to account for factors outside industry control. For example, part of the reason the system falls below the NZWEM under the SOSA Reference case is due to the significant unexpected decline in domestic gas production. An important design principle should therefore be that compliance is rationally tied to controllable factors and avoids punishing factors outside the control of those who are captured by the obligation.

Another key design question is not only how the proposed obligation would change incentives for obligated participants, but also how it would alter incentives for suppliers of qualifying firm cover. For example, a key question we have is how the 10-year HFOs and Huntly Security Energy Reserve would be treated under the regulation. Would they be treated as qualifying cover for the purpose of assessing compliance by Genesis' contracted counterparties, but load when considering Genesis' exposure under the obligation? When coupled with the Code-regulated Non-Discrimination Obligations, this may change (reduce) incentives to supply firm cover, counter to the policy objectives.

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.

As noted, it will be important to review the security standards and the SOSA to ensure they are fit for purpose, particularly if they are to be relied on for triggering regulatory obligations and compliance. Key design issues to address in the SOSA will be as follows:

- Modelling of generation capacity and energy output. We recommend the SOSA modelling include a "contracted scenario" showing energy output that is contracted or expected to be commercially viable. This may mitigate the risk of the SOSA over-estimating the availability of thermal plant that may not be commercially viable.
- Modelling of demand. As noted in Concept Consulting's submission, the SOSA has historically significantly over-estimated demand growth. Under the proposed LTO, this

would risk the system building too much supply, with inefficient and costly outcomes for consumers.

- Updating the Winter Energy Margin and ensuring the threshold for triggering an obligation is optimised. For example, we do not think very small, temporary shifts below the WEM should trigger an obligation, hence it may be necessary to define materiality. Accounting for temporary movements based on unexpected plant outage or weather will also be important.
- Accounting for the long lead times for commissioning new generation. The WEM should account for new plant under construction or in planning, consent or connection phases (as is the case with the current SOSA). As noted, the regime should also allow for third-party delay.

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.

We agree in principle. It may be difficult in practice for MBIE or the regulator to look into contractual terms that deal with counterparty failure, project delay, force majeure or similar events, terms and conditions of which are likely to be commercially sensitive. Any regime will need to account for the real-world practicalities of large complex plant and network infrastructure, and it will be important to avoid imposing liability on the provider of the contracted risk management solution in a force majeure scenario.

Other constraints that may impact the ability of obligated participants should also be considered, including for example delays to resource consent approvals and delays to transmission or distribution grid connection.

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.

In principle we agree penalties will be necessary for the regulation to achieve its objective. Ideally penalties should be calibrated to the actual cost resulting from any non-compliance, although in practice this may be difficult to calculate. Without more detail on regulation design and MBIE's assessment of costs and benefits, it is difficult to comment more definitively on the proposed penalties.

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.

See our views above.

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 proposed Short-term Obligation. Our view is that the market is already incentivised to maintain fuel and use hydro efficiently and therefore there is a risk adding a new STO will only add compliance risk and cost. While the proposed STO could increase energy security / resilience, particularly as domestic gas production continues to decline, it will likely only do so by increasing fuel supply above an efficient level with the result of higher prices. While this may reduce spot price volatility, it will likely do so at the cost of higher contracted hedge prices. For more detail on the risks, see Concept's report attached to the ERGANZ submission.

A case could be made that a well-designed LTO could render a STO unnecessary, particularly as the LTO would cover both capacity and energy. That is, an obligation to maintain the NZWEM and NI/SI WCM could solve the problem.

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.

See our comments above in response to the proposed de minimis threshold for the LTO, which are largely also relevant to the STO. Any de minimis threshold should be set at a level that balances the need to avoid unnecessary compliance costs on very small wholesale participants while ensuring incentives are rationally and fairly distributed throughout the system. We see risks of moral hazard and free-rider dynamics from imposing a STO on a small subset of wholesale market participants; indeed, there is a risk the de minimis threshold as proposed could exacerbate the problem by creating a perverse incentive for non-obligated participants *not* to contract hedge cover as they know system risk has been covered by obligated participants and therefore the risk of higher spot prices due to scarcity is lower. In practice, this will expose these participants to the risk of high prices occurring due to things the proposed obligation can't capture (asset or supply chain failure etc.). It is precisely these unexpected circumstances that impacted upon spot-exposed firms in 2024.

We also think regulations should avoid creating a disincentive on wholesale market participants to expand their generation capacity, particularly given the Energy Competition Taskforce has an objective of increasing competition and liquidity in the hedge market. Similarly, if the market responded to a STO by establishing an HFO-type arrangement, the participant offering plant and fuel under such an arrangement (for example, Genesis) would be expected to offer access to other market participants (independent retailers, etc.) on the same terms. However, it would be problematic if we are compelled to offer firming contracts on the same basis to all participants while only a small subset of participants bear compliance risk if cover is short.

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.

Our view is that prices (in the forward curve and forecasts) are already effective at signalling future supply and incentivising wholesale market participants to respond appropriately. Any additional obligation based on an arguably arbitrary regulated trigger of the kind proposed is likely to result in over-supply beyond what is efficient and therefore lead to higher prices.

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.

We do not support introduction of a STO.

Should government introduce a STO, we expect the market would respond proactively to any STO by entering into contracting arrangements that give the system optionality around volume and deliverability, for example by a fixed volume opt-out approach.

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.

In principle, yes. See our comments above regarding design of a LTO. As noted above, any regulated dry year obligation should be allocated rationally across the system and capture as much of the market as is possible while exempting very small wholesale market participants for example social retailers. This will avoid free-rider dynamics and ensure incentives and costs are rationally and fairly dispersed across the system.

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.

As noted, regulation should be technology and fuel neutral and allow the market to solve the problem, particularly as a portfolio of solutions is likely to be the most efficient and reliable approach.

As noted above under the LTO section, a key design question is not only how the proposed obligation would change incentives for obligated participants, but also how it would alter incentives for suppliers of qualifying firm cover. For example, a key question we have is how the 10-year HFOs and Huntly Security Energy Reserve would be treated under the regulation. Would

they be treated as qualifying cover for the purpose of assessing compliance by Genesis' contracted counterparties, but load when considering Genesis' exposure under the obligation? When coupled with the Code-regulated Non-Discrimination Obligations, this may change (reduce) incentives to supply firm cover, counter to the policy objectives.

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.

It will be practically difficult for the Authority to assess the firmness or adequacy of cover. Ahead of any obligation being triggered (ie before there is a case of possible non-compliance), any compliance should be aligned to inputs to an updated NZWEM and/or NI/SIWCM based on transparent and agreed assumptions and methodology. Should the system ever enter into a deficit triggering a response or compliance period, then the Authority would likely need to look into participants' physical and contracted supply and contracted demand.

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.

There is an extent to which no market design or regulations can ever be "perfect", and even markets with sophisticated contracting arrangements may not be able to cover for every risk. Any regulated obligation must include safe harbours for failure to perform, reflecting the practical realities of the energy system. MBIE should consult on guidance on how these safe harbours would apply, with examples.

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.

We agree that penalties should be calibrated to incentivise and influence market behaviour, otherwise the regulations may not solve the stated problem. Without more detail on regulation design and MBIE's assessment of costs and benefits, it is difficult to comment more definitively on the proposed penalties.

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?

Please explain your views.

See above. Also see ERGANZ's submission on this point. We agree that both scarcity pricing and the Customer Compensation Scheme are directed at the same end-state as the STO.