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Consultation Paper – Potential Solutions for Peak Electricity Capacity Issues

Thank you for the opportunity to provide feedback on the Electricity Authority's consultation paper "*Potential Solutions for Peak Electricity Capacity Issues*" (**Paper**).

We consider that:

(a) Consumer, business and political appetite for any material disruption in electricity supply is very low as the events of 9 August 2021 showed. This is also reflected in the new Government's identification of energy security, particularly 'keeping the lights on' during winter, as a high priority. This appetite will decrease further as customers and businesses electrify more of their lives and activities, and Governments look to make significant progress towards achieving New Zealand's decarbonisation objectives.

(b) 2024 and 2025 winter capacity risks may materialise quicker than anticipated. The 2023 winter demonstrated the fragility of our system, where four low residual events - driven by reduced thermal capacity, high peak demand and wind generation variability - would have led to grid emergencies had the industry not worked together to delay or cancel planned outages and commit slow start thermal units. Factors that contribute to this ongoing fragility include: unprecedented peak demand; fuel availability and unplanned outage risks; and the challenges with short term demand forecasting and the increasing volumes and variability of wind generation.

(c) Given this context, system reliability and the wider costs of supply disruption, should be given greater consideration when assessing trade-offs and potential solutions. Reliability – not just lower cost – is in the long-term interest of consumers.

(d) Market driven solutions within the existing market design are preferred but work on alternative solutions should continue in parallel. Genesis' thermal generation mix at Huntly (ideally on biomass and gas with coal as critical backup) represents the best solution for managing peak

demand capacity (and dry year) risk, and we are exploring new peaking and firming products to offer the market. We reiterate that the continued economic viability of the insurance provided by the Huntly Rankine units will be determined by the market, and that Genesis will not continue to hold excess backup energy storage on the system's behalf absent commercial arrangements to pay for it.

(e) An alternative integrated standby ancillary service cannot be implemented for winter 2024, or potentially, for winter 2025. However, we strongly recommend that the out of market solution that was proposed by the CEO Forum in 2022 is progressed. Providing Transpower with tools to economically constrain on assets (such as the Rankine units) to cover winter demand peaks is a prudent contingency if a market solution is not feasible or does not materially mitigate these risks, or in respect of Winter 2025 and beyond, if BESS and demand response progress proves slower than the Authority assumes. Had work commenced when it was first proposed, we would be going into the 2024 and 2025 winters with a pragmatic short-term solution.

(f) OTC peak and super peak products can be part of the solution to managing peak capacity risk if market participants are willing to pay for these (and recognise that where these are backed by the Rankine units, they are supported by coal).

(g) There are credit risk and settlement challenges with a centralised platform for offering standardised OTC products given the bilateral nature of these contracts. While we support investigating standardised products and a centralised platform, we do not support mandatory market making given the cost and complexity in an OTC context. If it becomes clear that market making support is required, then a commercial incentive-based market making scheme funded by those who benefit from the service should be the preferred design. The voluntary commercial market making framework for ASX NZ electricity futures provides a good template for co-designing a scheme.

(h) BESS and demand response solutions are critical both to peak capacity issues and supporting New Zealand's transition to a low emissions economy. We support the Authority's proposal to prioritise workstreams in these areas; in particular, improving BESS access to the spot, reserves, and ancillary services markets. We ask that this work is prioritised and accelerated.

We discuss these in more detail below.

Increasingly low appetite for supply disruptions and greater consideration of reliability

The Paper highlights the complexity, and many of the trade-offs, in managing peak capacity risks across different time horizons.

We agree that accurate price signals underpin efficient capital and resource allocation, and that high levels of reliability must be balanced against the costs to consumers for providing this reliability. However, other factors should also be considered when assessing peak capacity solutions. These include:

(a) The cost of disruption to consumers and businesses, and second and third order effects, such as lost confidence in an electricity system that is fundamental to achieving New Zealand's Net Zero objectives.

(b) Higher expectations of reliability. The 9 August 2021 outages demonstrated the very low consumer, business and political appetite for electricity supply disruptions. Indeed, the new Government has identified energy security as a high priority, and the new Minister of Energy has stated that 'keeping the lights on' is his top near-term energy portfolio priority. With electricity demand forecast to grow significantly over the coming years as consumers and businesses electrify more of their lives and activities, there will be even less appetite for disruption, and the economic cost of such disruptions will increase.

(c) There is also in our view a real risk that reduced reliability (or the perception of the same) results in a slower transition as consumers lack the confidence to electrify. Demand growth will ultimately dictate the speed with which new renewable generation is built, and is a key driver in the achievement or otherwise of the Government's goal to double renewable electricity generation by 2050.

While these may be difficult to quantify, they are relevant considerations when assessing potential solutions. They highlight, and better inform, the trade-off between minimising the risks and consequences of disruption, against the costs of provision and any potential price distortions and market inefficiency. It is also important to acknowledge that a reliable system is also in the long term interests of consumers. There is an implicit assumption in the Paper's commentary that consumers would not be prepared to accept a degree of market inefficiency in return for greater reliability in the short to medium term given the winter 2024 and 2025 risks. We consider this unlikely to be correct. Either way, the assumption should be tested.

Similarly, the standards used by the System Operator to assess winter energy and capacity margins were last reviewed in 2017, and as the Authority notes, were not designed to consider consumer preferences for supply reliability. The Authority further notes that no periods of reserve or energy shortage from 2018-2020, and

the very low shortage hours in 2021 and 2022, suggest that irrespective of the standard used, the electricity system delivers high levels of reliability.

We agree that New Zealand enjoys a highly reliable system, and that 100% reliability is not feasible. However, there have been significant changes to the electricity market since 2017 and the data referenced by the Authority can also be interpreted as an early indication of weakening reliability. We also reiterate the points made by the CEO Forum concerning the 2023 winter peak risk that measuring actual shortages only does not reveal the effort taken to avoid shortages, the number of near misses and the uncertainties in the system on winter peaks that have to be managed.[1]

The Authority is considering a review of these standards as part of its 2024/25 work plan. We believe that a review is necessary, and that it should consider whether, and how, reliability preferences and the unit commitment problem can be taken into account.[2] In relation to the former, market conditions and perceptions of risk have changed since the 2018 Transpower/PWC value of lost load study. We suggest that an updated study be included as part of this work.

2024 and 2025 Winter Capacity Risks Elevated

We agree with the Authority (and Transpower[3]) that managing peak capacity risks during the 2024 and 2025 winters will be challenging - 2025 potentially more so, with the significant reduction in thermal generation capacity when TCC retires.

These risks could, however, materialise quicker than anticipated.

The 2023 winter demonstrated the fragility of our system, where four low residual events - driven by reduced thermal capacity, high peak demand and wind generation variability - would have led to grid emergencies had the industry not worked together to delay or cancel planned outages and commit slow start thermal units.

Factors contributing to this ongoing fragility include: unprecedented peak demand (which the System Operator expects to continue); fuel (gas) availability and unplanned outage risks; and the challenges with short term demand and generation forecasting pose, including for unit commitment decisions. As we have previously discussed with the Authority, the complexity of thermal unit commitment has increased and is likely to continue increasing with the growth in intermittent renewables, and this increases system risk (see chart below for system reliance on the Rankine units). Accordingly, Genesis supports the initiatives to improve intermittent generation forecasting given the costs and risks arising from

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[1] CEO Forum's submission dated 16 December 2022 in response to the Authority's *Driving efficient solutions to promote consumer interests through winter 2023* consultation paper.

[2] For the reasons set out in the CEO Forum's submission dated 16 December 2022 in response to the Authority's *Driving efficient solutions to promote consumer interests through winter 2023* consultation paper.

[3] Winter 2024 Outlook, Transpower, 31 January 2024.

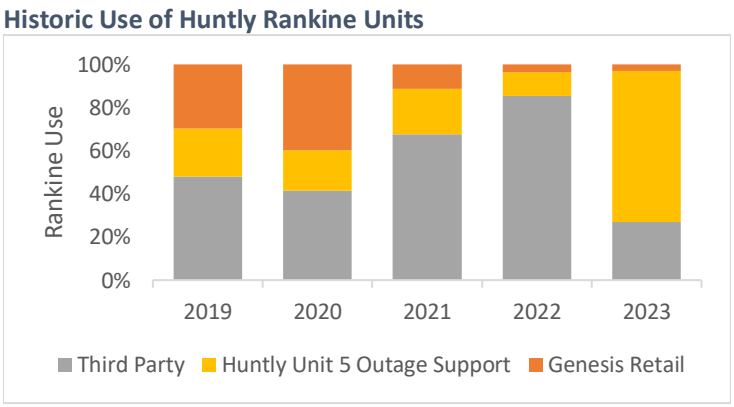
inaccuracies, and ask that the Authority accelerate a decentralised option with incentives and penalties for winter 2024.

Market driven solutions preferred

Market driven solutions within the existing market design is preferred, and as we discuss further below, should be accompanied by work on alternative solutions.

Every electricity supplier and customer on the grid in New Zealand benefits from Huntly's thermal generation at some point for security of supply. A live example is the support which Huntly thermal generation is currently providing to the North Island during the HVDC outage.

The Huntly Rankine units provide essential back up for New Zealand, and as the chart below demonstrates, serves New Zealand's energy system beyond Genesis' needs.



Genesis has previously offered OTC products to the market with limited take up. This was driven principally by disagreement on price and, in some cases, sensitivity to coal.

OTC peak and super peak products can be part of the solution to managing peak capacity risk if market participants are willing to pay for these, and acknowledge that where these are backed by the Rankine units, they are supported by coal.

Genesis' thermal generation mix at Huntly represents the most cost-effective option for managing peak demand capacity (and dry year) risk and Genesis is exploring new peaking and firming products to offer to the market.

The market reaction to those products will ultimately determine how long the Rankine units can economically remain part of this insurance mix, ideally, in time, on biomass and gas with coal as critical backup.

We reiterate that:

(a) the continued economic viability of the insurance provided by the Huntly Rankine units will be determined by the market; and

(b) Genesis will not continue to hold excess backup energy storage on the system's behalf absent commercial arrangements to pay for it.

Work should continue on alternative solutions in parallel

Genesis agrees that an alternative integrated standby ancillary service cannot be implemented for winter 2024, and potentially, for winter 2025.

However, we strongly recommend that the out of market solution that was proposed by the CEO Forum in 2022 is progressed. Providing Transpower (as System Operator) with the tools to economically constrain on assets such as the Rankine units to cover winter demand peaks is a prudent contingency if, for example:

(a) market driven solutions are not feasible (or do not materially mitigate these risks);

(b) gas supply or unplanned outage risks materialise; and/or

(c) in respect of Winter 2025 and beyond, grid scale BESS and demand response progress proves to be slower than the Authority assumes.

Had work commenced when it was first proposed, the industry would be going into the 2024 and 2025 winters with a pragmatic short-term solution.

The existence of a time bound and well-designed solution that can be quickly implemented if required, does not necessarily lead to distortion of long term price signals for investment or other unintended consequences.

While the Authority rightly recognises that there is a risk that this occurs, further consideration should be given to the probability of that risk and whether system reliability should be given greater weight in the near term given that probability, and the matters discussed at the introduction to this submission.

We note that:

(a) The organisations represented by the CEO Forum comprise a significant portion and cross-section of the industry, and in proposing an industry led solution, considered that these risks could be managed, and that this was an appropriate short term solution given the circumstances.

(b) If there are delays in the investment in BESS and other new technologies, the Authority's annual investment and other surveys should provide insights as to whether these were driven by the relevant

out of market solution or other factors, and measures taken to address this accordingly.

(c) International experience with standby / out of market schemes while providing some useful insights do not appear to consider the counterfactual. That is, the potential costs of disruption without those measures in place.

BESS and demand response workstreams should be prioritised and accelerated

Grid scale BESS and demand response are critical both to peak capacity issues and supporting New Zealand's energy transition. Genesis therefore supports the Authority's proposal to prioritise workstreams in these areas, and in particular, improving BESS access to the wholesale market and ancillary services markets.

Removing regulatory obstacles and improving market access so that BESS can provide a broader range of services would also help reduce revenue stream uncertainty, providing more clarity for investment decisions. We recommend prioritising and accelerating these workstreams to facilitate wider adoption of BESS over the medium term.

Market rules must evolve so that the potential provided by new technology can be fully realised.

Centralised platform for OTC super peak products

OTC super peak products can be part of the solution to managing peak capacity risk and as discussed above, Genesis is exploring products to offer the market. OTC peak products (and demand response products) are, however, typically tailored to the contracting parties' objectives and risks.

We note that there are credit risk and settlement challenges with a centralised platform for offering standardised OTC products given the bilateral nature of these contracts. Similarly, standardisation becomes challenging where the product is backed by specific plant. Further, if margin costs, credit / prudential support considerations mean that an exchange traded product is not feasible, the same issues presumably arise with a centralised OTC platform, which may be exacerbated without the infrastructure and synergies of an exchange, clearing and settlement service providers.

We would support a co-design process with the Authority for OTC products as suggested by the MDAG, and note the successful collaborations between the industry and the Authority on the ASX market making scheme and OTC voluntary code of conduct. However, it is important to first test whether an exchange traded super peak product should be pursued so that the existing infrastructure, including market making, can be leveraged. Amongst other things, this would provide a

counterfactual for assessing the costs and benefits of a standardised OTC scheme.

While we support investigating a platform, we do not support mandatory market making. Market making as this comes with considerable cost and complexity. It is not evident that this service is necessary, and we note that the MDAG recommendation was contingent on whether there was a need to strengthen competition.

If it becomes clear that market making support is required, then:

(a) a commercial incentive-based market making scheme funded by those who benefit from the service should be the preferred design; and

(b) the design and scheme terms should be informed by a competitive procurement process, which balances the benefits and costs of different levels of service and encourages least cost provision.

The voluntary commercial market making framework for ASX NZ electricity futures would provide a good template for co-designing a scheme.

Please don't hesitate to contact me should you wish to discuss further.

Yours sincerely

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