Potential solutions for peak electricity capacity issues

Consultation paper

12 January 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

Supporting the increased electrification of the economy

With the drive to electrify the New Zealand economy to meet our net zero carbon by 2050 obligation, our already highly renewable electricity system is set to change drastically over the coming years. Forecasts of an increase in electricity demand of the order of 50% will require significant investment in renewable generation. Much of this investment is likely to be in the form of variable renewable generation, such as wind and solar. This raises the question of how to reliably and affordably supply consumers' electricity needs when the wind is not blowing, and the sun is not shining.

Incentivising flexible resources, such as battery energy storage systems (BESS), demand response and new commercial markets will play a critical part in meeting this flexibility challenge. This challenge is already creating issues through winter peak coordination, as renewable generation displaces slow-start thermal plant from the market for much of the time, making thermal generation commitment decisions more challenging.

We need to strike a balance between incentivising new technologies and business practices to support security of supply and confidence in the electricity supply chain and minimising the cost impact on consumers. One way of doing this is to ensure that consumers are included in the solutions to manage variability. Some retailers and third parties are already doing this through demand shifting retail tariffs that encourage consumption away from peak demand periods or the use of domestic BESS to provide system support when it is needed most.

The Electricity Authority Te Mana Hiko is conscious that initiatives implemented to manage near-term issues, say the next one to two years, should not disincentivise innovation and investment for the medium and long term. The timeframe needed for the development and commissioning of new physical resources is such that the near-term problem becomes one of coordinating the currently available resources as efficiently as possible. Incentives must avoid 'locking in' current technologies and business practices at the expense of medium and long-term innovation.

With this in mind, we have considered a number of options to address the peak coordination issue over the short and medium-term:

- Short-term (12 months): improved coordination of existing generation resources, improved market visibility of flexibility, settings are right for emerging technologies, early investment in flexible resources coming online
- Medium-term (2-4 years): wider adoption of BESS and distributed energy resources, wider participation in ancillary service markets by generators, industry, and other consumers enhancing the economics of flexible resources
- Long-term (5+ years): significant new generation and storage options online delivering sufficient flexible renewable energy options to balance security and affordability for the long-term.

Security of supply context

Consideration of security of supply, in the context of the electricity system, falls broadly into two areas:

- **Capacity**, which refers to the availability of generation and transmission assets to meet peak electricity demand at any point in time.
- **Energy**, which refers to the availability of generation and transmission capacity to meet expected national demand over an extended period of time, typically across the winter months.

It is important to note that transmission and generation outages, both planned and unplanned, are key factors to consider when assessing security of supply.

As the power system transitions to meet the Government's net carbon zero by 2050 target, the Authority is working to ensure that consumers receive a reliable and affordable electricity supply.

However, this is not something we can do alone, and a broad range of government agencies and market participants are contributing to this work to ensure the energy transition happens in a way that efficiently manages the supply risk to consumers.

The Ministry of Business Innovation and Employment released its consultation on *advancing New Zealand's energy transition* in late 2023. This work tested assumptions and policy directions from fuel supply to future generation investment, as well as electricity market settings for the transition.

The Market Development Advisory Group (MDAG) has been considering the market settings necessary for the efficient operation of the wholesale market in a low carbon future.

The focus of this consultation paper is the management of capacity issues

Historically, consideration of security of supply in the New Zealand context has focused on the dry winter issue. That is, the susceptibility of the power system to energy shortfalls due to a prolonged period of low or no rainfall in the South Island hydro catchments.

The monitoring of, and regulatory settings relating to the management of, a potential dry winter situation have evolved over a number of years. There is a well understood process to manage the security of supply risk in the event of low hydro storage levels.[1]

The management of capacity margins has not been the focus of the power industry historically as, until recent years, there was little growth in peak demand or energy consumption. This provided no signal that investment in new generation was needed. The investment that did happen tended to be replacing retiring generation. Some fast-start gas peaking generation was built during this time, though the bulk of new investment was in the form of wind generation with some geothermal assets providing an uplift to baseload capacity.

[1] The last dry winter storage sequence occurring in 2008.

The recent drive for electrification of the economy has seen a sharp increase in peak demand over the last two years. This, coupled with thermal fuel supply issues and the displacement of thermal base-load generation, has led to resource coordination issues when managing peak demand periods. In simple terms, there is not enough capacity available to be delivered to ensure electricity supply meets demand.

This has become a particular focus for the winter months, ironically when hydro lakes are reasonably full and the incentives to run thermal generation are weak.

As the level of intermittent generation, such as wind and solar, increases, there is a growing need for other resources to provide the flexibility required to compensate for the short-term variability in output, for example, during cold, cloudy, windless mornings. This management of intermittent generation variability is referred to as 'firming'.

The installed generation capacity at the end of 2022[2] was over 9,400MW. This compares to an all-time peak winter demand of record of 7,129MW on 9 August 2021. A number of generators are on scheduled maintenance outages at any given time, even so, the issue for peak demand management in the near-term becomes one of efficient coordination of the available resources at any given time.

After accounting for outages, the remaining resources need appropriate market information and pricing signals to make a decision on whether to commit flexible capacity. Slow-start thermal generation, such as the Huntly coal-fired Rankine units or large gas turbines such as Huntly unit 5 and the Taranaki Combined Cycle unit, require the strongest signals earliest.

If the units are not already committed to run at least part of their capacity, preparing them to run can take upwards of nine hours and incur not insignificant costs.

During periods of lower hydro storage this is generally an easier decision to make, if it is needed to be made at all, as the higher average wholesale prices will encourage these units for longer periods to conserve more scarce hydro storage for peak periods.

This situation has been exacerbated by the increase in low-cost renewable generation reducing the wholesale price to the point that it is not economic to run thermal plants for extended periods.

This operational coordination issue is most pressing in the near-term

The operational coordination challenges described above are an inherent part of New Zealand's move to electrify the economy. Participants will need clear signals that flexible resources are needed at times, and the system operator will need to carefully coordinate resources provided to it by participants to manage capacity issues over this period.

Fast-start gas turbines and hydro generators have been the electricity industry's traditional response to the need to vary generation rapidly. Encouragingly, the increased need for firming is driving innovation and new technologies are starting to emerge, and in the

[2] MBIE. *Electricity statistics*. Available at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/#Electricity%20Generation

medium-term BESS and distributed energy resources will play an increasingly important role.

Grid-scale and aggregated-domestic-battery-storage systems are being used and trials are underway using other resources such as electric vehicle chargers and batteries.

Transpower's October 2023 Whakamana i te Mauri Hiko monitoring update[3] notes a surge in interest in batteries attached directly to intermittent renewable generation units as well as stand-alone grid-scale batteries. New Zealand's first utility-scale BESS[4] was commissioned in December 2023 with the first grid-scale BESS expected to be completed in late 2024.[5]

Market participants are already responding to this challenge with initiatives that provide flexibility in the short term and additional resources in the mid to long-term. To gain a clearer picture of these investments, the Authority has refreshed its 2022 investment survey and will be releasing the results in early 2024.

We are encouraged by the number of initiatives that will have an impact on capacity coordination in the near-term. These include:

- Retailer tariffs encouraging demand shifting away from peak demand periods,
- The coordination of domestic battery storage systems in the demand response and instantaneous reserve markets,
- The start of investment in utility and grid scale battery systems

In the medium-to-long term, there is also a strong pipeline of committed renewable generation with accompanying battery storage. This battery storage will be able to address some of the flexibility requirements introduced by the increase in variable renewable generation.

Additionally, it is expected that, as less of the flexible capacity of hydro generation is needed to meet baseload consumption, that flexibility will be available to help support the broader flexibility needs of the power system.

Gas will also play a role, both in the short-term as one of the few options currently available to address an urgent capacity need, and the medium-term should industry invest in additional gas peaking plant.

As discussed earlier, we expect the coordination issue to abate over time as the existing hydro generation performs more of a firming role alongside grid scale battery storage and distributed energy resources provide increased short-duration flexibility to manage variable renewable generation.

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[3] Transpower. *Investment in flexible resources set to ease renewable transition.* October 2023, 19. https://www.transpower.co.nz/news/investment-flexible-resources-set-ease-renewables-transition

[4] WEL Network. *Launch of New Zealand's first utility scale battery energy storage system (BESS).* Available at: https://www.wel.co.nz/about-us/news/launch-of-new-zealands-first-utility-scale-battery-energy-storage-system-bess/

[5] Meridian. *Meridian to build Ruakākā Battery Energy Storage System.* December 20223,15. Available at: https://www.meridianenergy.co.nz/news-and-events/meridian-to-build-ruakaka-battery-energy-storage-system

We explore short and medium term options

We are encouraged by the new technologies and innovations coming to market but recognise that the right signals are needed to bring these technologies to market and that, in the short-term, options are limited.

Given the timeframes needed to procure and commission physical resources, such as generation and BESS, options for the short-term are limited to coordinating resources already in place or in the process of being implemented. Changes in business practice can be faster to implement but may still require upgrades to, or replacement of, physical plant and changes to contractual arrangements.

We acknowledge the trade-off between incentivising new resources and business models and maintaining security of supply. This balance is something that the Authority continually monitors and is prepared to take action to manage, in conjunction with the system operator.

Capacity supply issues can also arise through the unexpected loss of resources, such as an unplanned outage of a significant generator.

In these circumstances, it may be prudent to implement a temporary solution while market participants respond to the issue.

These issues are not easy and requires the consideration of all sector participants. For this reason, the Authority considers it timely to test its view, and that of others.

As part of this paper the Authority considers the need to procure standby reserve as an additional ancillary service to provide firming capacity, both as an integrated part of the wholesale market and outside the wholesale market. Standby reserve refers to the capacity to effectively address substantial, unforeseen fluctuations in energy demand.

Options to support capacity now must not hinder mid and long-term investment signals for flexibility

The flexibility initiatives being implemented now by participants are in response to the market signals indicating the need for those resources. Muting those signals could hinder further development of those resources and extend the time over which the coordination issues persist.

Implementing any short-term reserve scheme must support further investment in new flexible resources while providing a net improvement in security of supply. In this paper, we have considered some potential options for an interim security product. None are without drawbacks and the potential to distort investment signals but we would appreciate your feedback on them and explore any further suggestions that you may have.

Financial incentives to provide flexibility

The financial hedging market, hosted on the Australian Stock Exchange (ASX), currently trades ‘peak’ futures products alongside baseload products. These peak futures products allow participants to purchase contracts for electricity that provide cover between the hours of 7am and 10pm on business days. The MDAG report recommends the development of ‘new flexibility products (standardised)’ (recommendation 8). An example of such a flexible product is the Australian National Electricity Market's 'super peak swap' product. This product is designed to provide cover during high demand periods during the morning and evening peaks but provides no volume cover during the lower demand middle of the day. This would allow flexible supply and demand side flexibility to participate in the forward price discovery process and obtain more certain revenues while supporting the management of peak demand.

A further recommendation, recommendation 24, proposes enhancing price discovery through mandated market making for these flexibility products. In this paper we ask whether there is a case for accelerating the introduction of market making obligations to further support the development of flexible resources in the wholesale market.

Accelerating flexibility investment through improved market access

In the near term, we consider that the Authority's efforts are best focused on checking for and removing any regulatory roadblocks to investment and innovation in BESS and in demand flexibility services. This includes ensuring that these resources can easily participate in existing ancillary service markets.

Battery Energy Storage System (BESS) participation in the wholesale market

The market system cannot easily model the bi-directional nature of BESS. To signal both the ability to consume electricity when charging and export energy when discharging, BESS must submit separate offers for each state. This has implications for the way that BESS can offer reserves and must manage its market offers to ensure that it can comply with dispatch instructions that it receives. This could make it difficult to reflect the full flexibility of the BESS in the wholesale market.

Further, a resource must have a cleared energy offer in the wholesale market to be dispatched for the frequency keeping ancillary service. This means that, even though the battery consumption is fully controllable when charging, this portion of its capacity cannot be dispatched into the frequency keeping service. This would limit the revenue available to the battery and put tighter limitations on the minimum size of BESS that could participate.

Demand response in the frequency keeping market

We note that the Australian national electricity market's frequency control ancillary service (FCAS) divides its services into up and down regulation services, both of which are explicitly open to demand side participation. Further engagement with the Australian Energy Market Commission (AEMC) will be needed to determine the level of participation of demand side resources in the FCAS market and the benefits of opening the frequency keeping market to demand side flexibility in New Zealand.

Developing an integrated standby ancillary service

As we indicated in our March 2023 winter measures decision paper,[6] the implementation of an integrated standby ancillary service would be a significant undertaking. This paper

[6] Electricity Authority. *Driving efficient solutions to promote consumer interests through winter 2023, decision.* March 2023. Available at: https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

provides our preliminary thinking on possible solutions and the pros and cons associated with an integrated standby ancillary service.

There is no quick, easy solution and if we do decide to progress an integrated standby ancillary service, the further analysis and development required to get it right for consumers and industry could take a number of years.

For this reason, we do not consider an integrated standby ancillary service to be a quick measure to support winter peak supply coordination in the near term. However, we consider it important to explore this issue further should it be needed for the long-term management of capacity risk.

Out of market solutions

Out-of-market solutions have the benefits of potentially shorter implementation timeframes due to the ability to avoid making changes to the market system software and administration process. However, out-of-market solutions will still need the development of some form of commercial arrangement, the negotiation of which can be time consuming with no guarantee that a final agreement could be reached.

These contracting arrangements may lock in existing flexibility arrangements, disincentivising investment in, and participation of, new technologies and practices. Further, any out-of-market solution may impact spot market pricing signals for the longer-term investment in more efficient measures and technologies.

This is because the Authority considers accurate price signals are necessary to encourage investment and/or demand response in the right place at the right time. This is supported by MDAG's observation that clear price signals are needed for efficient resource coordination. We are concerned that an interim standby ancillary service would not provide long-term signals for investment, so it would not incentivise investment in new technologies or resources. This could prolong these current capacity challenges.

Have your say

The Authority invites feedback on each of the proposed solutions (both interim and long term) and we encourage submitters to provide additional data and/or any alternative solutions which would present a lower cost on consumers.

We also welcome feedback on the ways to incentivise demand response and BESS uptake for the long-term benefit of consumers. The Authority is also keen to gather information from industry on available demand response. Please provide information through our survey (https://info.ea.govt.nz/sl/1b9596).

Information on how to submit is included in Section 1 of this paper.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The purpose of this paper is to consult with interested parties on the Electricity Authority Te Mana Hiko's proposed solutions to manage peak electricity demand capacity issues.

1.2. This paper aligns with our strategic ambition of system security and resilience and falls under the theme of managing peak winter electricity demand to mitigate the risk of unplanned power outages for consumers.

How to make a submission

1.3. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix C. Submissions in electronic form should be emailed to OperationsConsult@ea.govt.nz with "Consultation Paper – potential solutions for peak electricity capacity issues" in the subject line.

1.4. If you cannot send your submission electronically, please contact the Authority (OperationsConsult@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.5. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part and

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.6. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.7. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.8. Please deliver your submission by 5pm on Friday 1 March 2024.

1.9. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority at OperationsConsult@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Winter peak capacity issues

Aotearoa New Zealand's electricity system is transforming rapidly

2.1. New Zealand's electricity system is transforming at an unprecedented scale and pace. The opportunities are significant, as are the immediate and emerging challenges. Existing regulation needs to keep up with a system that is fundamentally changing.

2.2. Current arrangements appear to have delivered satisfactory reliability for many years and continue to do so. However, it is important to consider not just how well the existing arrangements work in today's environment, but how well these arrangements will meet the needs of the transition as we electrify New Zealand's economy.

2.3. The country is transitioning to a greater penetration of variable renewable generation. The proportion of firm or dispatchable generation, such as thermal or hydro-based generation, has also reduced over time. This has coincided with an increase in peak demand as the drive to electrify New Zealand's energy needs has led to greater electrification of industrial and domestic heating as well as transportation.

2.4. We are working with generators, retailers, distributors, and the system operator to ensure an efficient transition to electrification. This will maximise the benefits to consumers, lead to lower electricity prices and a secure and resilient electricity system for generations to come.

High levels of reliability need to be balanced against the cost to consumers

2.5. Most consumers want a very high level of reliability in their electricity supply, given the costs and inconvenience associated with power cuts. However, it is important to note that lifting reliability imposes additional costs on consumers.

2.6. Further, it is not possible to achieve 100% reliability; all possible eventualities cannot be accounted for when building assets or implementing market measures. Unforeseen circumstances, such as the sudden loss of a major asset, cannot always be allowed for, especially when multiple events coincide. A balance must be struck between an acceptable level of reliability and the costs to consumers.

2.7. The industry currently operates on an established standard of reliability. The Security Standards Assumptions Document[7] (SSAD) sets out the assumptions and standards to be used by the system operator when assessing security of supply.

2.8. The settings in the standards form the basis of the system operator's evaluation of the following security of supply margins:

(a) New Zealand winter energy margin

(b) South Island winter energy margin

(c) North Island winter capacity margin.

[7] Electricity Authority. *Security Standards Assumptions Document*. November 2012, 14. Available at: https://www.ea.govt.nz/documents/166/Security_standards_assumptions_document.pdf

2.9. The standards represent an efficient level of reliability – that is, where the expected cost of shortage is equal to the expected cost of new generation. However, the standards are not designed to take into account consumer preferences for supply reliability.

2.10. The national cost-benefit analysis presented in these standards determines that up to 22 hours per annum of energy or reserve shortfall (as a result of a capacity shortage) is economic before additional investment in peaking generation is warranted. It should be noted that a reserve shortfall can occur without directly impacting consumer supply.

2.11. The SSAD was first published in 2012. The Authority last reviewed the standards in 2017, when no changes were made.[8]

2.12. Although the security standards have not been reviewed since 2017, we note that the level of shortages in recent years has been well below the level suggested by the standards.

2.13. In the first 10 months of 2022, there were 2.25 hours of reserve or energy shortage. In 2021, during which load was disconnected on 9 August, system operator reports indicate there were 6 hours of shortage in total. There were no periods of reserve or energy shortage from 2018 to 2020.

2.14. This suggests that, irrespective of the standards used in monitoring New Zealand's security of supply situation, the power system continues to deliver high levels of security of supply with the resources in place.

2.15. The examples of innovation in the demand side described later in this paper and the pipeline of consented and under-construction generation and battery storage systems shows that the wholesale market appears to be sending the right short and long-term signals for investment in security of supply. This suggests that the underlying approach is working well.

2.16. In short, while no electricity system can provide 100% reliability of supply, all parties involved in the power system can implement measures to mitigate the risk of interruptions to supply. The initiatives implemented for winter 2023 and the participant-led demand side flexibility initiatives (described later in this document) are good examples of this.

Q1: Do you agree with the principle that the winter capacity margin should be based on the trade-off between the cost of the hours of reserve or energy shortfall and the cost of the peaking generation needed to mitigate it? Do you have any other suggestions on factors the Authority should consider and why?

[8] At the time, we decided that the level of change to the SSAD suggested by the review was too small to justify amending the document. We are considering a further review of the SSAD as part of our 2045/25 work programme.

Recent industry concerns have related to peak capacity issues

2.17. While the fundamental design of the power system continues to deliver high levels of security of supply, there are specific, short-term challenges related to the peak electricity capacity that the Authority needs to consider.

2.18. The system operator coordinates available resources in real-time to serve demand and ensure sufficient reserves are on standby to cover pre-defined risks (such as the unexpected loss of the single largest generator or transmission circuit).

2.19. The ability of electricity supply to meet demand over different time frames is referred to as 'security of supply'. There are two broad forms of security of supply:

(a) **Energy**, which refers to the availability of generation and transmission capacity to meet expected national demand over an extended period of time, typically across the winter months.

(b) **Capacity**, which refers to the availability of generation and transmission assets to meet peak electricity demand at any point in time. This requires the near-term (from one week ahead to at real-time) coordination of the available resources. Efficient coordination relies on accurate forecasting of demand and intermittent generation as well as up to date knowledge of demand side flexibility.

2.20. This paper considers potential solutions to support the physical supply of electricity to meet peak capacity.

The winter peak capacity coordination challenge is a characteristic of the transition to a low-carbon economy

2.21. Pre-2021, the industry has focused on issues related to meeting energy needs over winter and so called 'dry winter' scenario planning. Recent winters have highlighted the need for more flexible resources to be available over winter peaks.

2.22. Since mid-2021, the system operator has reported that there has been a substantial increase in the frequency of trading periods when the available supply is tight (or insufficient) compared to projected electricity demand and normal reserve requirements.

2.23. This is, in part, due to the increased penetration of variable renewables and the transition to electricity as a primary fuel for industrial and domestic heating applications. The system operator expects these conditions to persist for the next two to three years.[9]

2.24. In New Zealand, demand for electricity is highest during winter. This is both in terms of the total energy consumed and peak demand.

2.25. After 10 years of relatively flat demand, the system operator reports that peak demand has been increasing at approximately 1.5 – 2% per annum over the last

[9] Transpower. *Winter peak analysis: 2024 and 2025.* April 2023, 4. Available at: https://static.transpower.co.nz/public/bulk-upload/documents/Winter%20Peak%20Analysis%202024-25.pdf?VersionId=J126IvIW3y7CfSA4Z5tst2PvzE5vNiuW

four years.[10] Our highest demand peak (7,129MW) occurred in August 2021 and the second highest (7,122MW) in August 2023. The average peak demand for winter 2023 was 5,858MW.[11]

2.26. As peak demand grows, more flexible capacity is needed to meet it. A key challenge is that most of New Zealand's new generation comes from intermittent generation sources.[12] Of all future generation projects being investigated or developed, 87% are intermittent in nature.[13]

2.27. As the level of intermittent generation increases, there is a growing need for other resources to provide the flexibility required to compensate for the short-term variability in output, for example, during cold, cloudy, windless mornings. This management of intermittent generation variability is referred to as 'firming'.

2.28. Fast start gas turbines and hydro generators have been the electricity industry's traditional response to the need to vary generation rapidly. However, the increased need for firming is driving innovation. Grid scale and aggregated domestic battery storage systems are being used and trials are underway using other resources such as electric vehicle chargers and batteries.

2.29. Growing renewable generation, both intermittent and baseload such as geothermal generation, is pushing old slow-start baseload thermal plant to be used more in a peaking capacity. As these technologies have lower operating costs than thermal plant, they tend to reduce the average wholesale market price. This erodes the commercial incentive to warm up slow-start thermal plant just in case they are needed to cover brief periods a few times a year. This has been exacerbated by the increasing carbon price and recent uncertainty in fuel availability increasing thermal plant running costs.

2.30. Much of New Zealand's traditional baseload thermal generation fleet is ageing, decreasing its reliability and availability. Unexpected loss of supply through unplanned outages and unexpected capacity reductions have been features of some recent tight supply situations. Climate-policy-related settings, such as the target of net zero long-lived gases by 2050[14] and increasing carbon emission costs, also mean there are few commercial incentives to (re)invest in thermal peaking

[10] Transpower. *Winter 2023 review.* October 2023. Available at: https://static.transpower.co.nz/public/uncontrolled_docs/Winter%202023%20Review.pdf?VersionId=Zxdbk14diwGA43UuzjYGV8IhGj44cbji

[11] Based on analysis of demand peaks from June to September 2023, 7am – 11am and 5pm – 9pm.

[12] These sources are called 'intermittent' because they cannot be controlled as they rely on the wind blowing or the sun shining to produce power.

[13] Transpower. *Winter 2023 review.* October 2023. Available at: https://static.transpower.co.nz/public/uncontrolled_docs/Winter%202023%20Review.pdf?VersionId=Zxdbk14diwGA43UuzjYGV8IhGj44cbji

[14] MBIE. *New Zealand Energy Strategy.* Available at: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/new-zealand-energy-strategy/

plant. This has led the system operator to signal the risk that flexibility needs are growing faster than flexible resources are being added to the power system.[15]

2.31. The challenge becomes more apparent when hydro lake levels are high. The abundance of low-cost hydro generation further reduces the incentives for slow-start thermal units to be kept warm. This could increase reliance on the remaining thermal peaking plant if there is an unexpected reduction in wind generation or increase in demand.

2.32. Peak summer demand is more than 10% lower than peak winter demand. This means that the system is less likely to run into capacity issues over the summer months. However, scheduled maintenance outages for generators or the high-voltage direct current cables (HVDC) coupled with low rainfall or unscheduled outages can lead to occasional capacity concerns outside the winter period. The frequency of these out-of-winter issues may increase as greater electrification of process heat applications drives generally higher demand peaks.

2.33. In November 2022, the system operator issued its review of the winter 2022 demand peaks and its view of the challenge for managing demand peaks in winter 2023.[16] This was accompanied by a security of supply assessment that reinforced the potential for supply shortages during periods of low thermal generation commitment.[17]

We expect the coordination challenges for winter 2024 and 2025 to be similar to this winter

2.34. While increasing innovation from industry participants to meet these capacity challenges is encouraging, effective coordination of existing resources is likely to be critical for the coming winters.

2.35. The system operator has previously expressed concerns about the outlook for winter 2024. Referring to its Security of Supply Assessment published in June 2022, the system operator suggested that that under certain scenarios the winter capacity margin could fall under the security standard in the Electricity Industry Participation Code (Code) as early as 2024.[18]

2.36. In January 2024, the system operator intends to publish a detailed analysis of the peak and energy demand challenges that it foresees for winter 2024 and beyond. In its review of winter 2023, the system operator notes that 'the sustained growth in demand and intermittent generation informs our view that the challenges in winter

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[15] Transpower. *Winter 2023 review.* October 2023. Available at: https://static.transpower.co.nz/public/uncontrolled_docs/Winter%202023%20Review.pdf?VersionId=Zxdbk14diwGA43UuzjYGV8IhGj44cbji

[16] Transpower. *System Operator winter review paper.* November 2022. Available at: https://static.transpower.co.nz/public/bulk-upload/documents/Market%20insight%20report%20-%20Winter%20Review%20-%2011%20Nov%202022.pdf?VersionId=QaQVHc8zmQ6_FpC_Ux7GOimodObF9Vt2

[17] Transpower. *Security of Supply Assessment 2023.* June 2023, 26. Available at: https://static.transpower.co.nz/public/bulk-upload/documents/2023%20SOSA%20-%20Final%20Report%20-%20Final%20Version.pdf?VersionId=3VV75p2zXTR_3kxn3HZPixEiiq9ipiJX

[18] Transpower. *Security of Supply Assessment 2023.* June 2023, 26. Available at: https://www.transpower.co.nz/system-operator/planning-future/security-supply-annual-assessment

2024 will be similar to this winter and demonstrates the need for investment in flexible resources to balance demand'(p. 6).[19]

2.37. Our analysis of the outlook for winter 2024 and 2025 supports this view (see Appendix A). We also note that during winter 2023:

(a) consumers did not experience forced power cuts due to coordination issues despite a number of challenges including significant plant failures, high peak demand periods and low thermal commitment due to high hydro storage

(b) improved information from the options implemented for winter 2023 along with cooperation by industry and improved communications from the system operator contributed to the positive outcomes for this winter

(c) high thermal fuel availability provided resilience against asset failures, but the reduction in capacity from these failures mean that the power system was vulnerable to any further asset failure or severe cold weather event.

2.38. Recent, significant, thermal-plant failures[20] have highlighted the need for options other than relying on, in some cases, ageing thermal plant for reliability. In particular, the three Huntly Rankine units are in the final decade of their expected operational life.[21] Contact Energy has also notified the market that it expects to retire the Taranaki Combined Cycle unit at the end of 2024.[22]

2.39. We expect the coordination challenges for winter 2024 and winter 2025 to be similar to this winter and note the importance of accelerating the uptake of demand response and BESS solutions to meet these challenges.

2.40. Given this context, we consider it is prudent to examine short and long-term solutions to support security of supply. The potential costs of these solutions will need to be weighed against the cost for consumers.

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[19] Transpower. *Winter 2023 review.* October 2023. Available at: https://static.transpower.co.nz/public/uncontrolled_docs/Winter%202023%20Review.pdf?VersionId=Zxdbk14diwGA43UuzjYGV8IhGj44cbji

[20] The loss of Huntly unit 5 until February 2024, Stratford GT22 until early 2025 and the runback of one of the Huntly Rankine units in October 2022 that contributed to one of the only 2 discretionary demand management events.

[21] MBIE. *2020 Thermal generation stack update report: prepared for the Ministry of Business, Innovation & Employment.* October 2020, 29. Available at: https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf

[22] Contact. *Contact delivers solid FY23 performance while investing for decarbonisation.* August 2023, 14. Available at: https://contact.co.nz/-/media/contact/mediacentre/2023/contact-delivers-solid-fy23-performance-while-investing-for-decarbonisation.ashx?la=en

3. Industry is working to better coordinate their resources

3.1. In our winter 2023 consultation paper,[23] we highlighted underlying incentive and information gaps which hindered the emergence of efficient generation and demand response coordination decisions.

3.2. To address these concerns, the Authority worked with the system operator to implement four changes to improve information provision to participants and resource coordination in the wholesale market.

(a) Provide better information on the headroom in the supply stack.

We published the forecast amount of supply that is left after demand, reserve and frequency keeping requirements have been met. By publishing this information, participants are able to monitor for potential 'low-residual'[24] situations and change their consumption and generation decisions in a more coordinated manner.

(b) Provide forecast spot prices under demand sensitivity cases.

Participants can better assess the impact of demand or intermittent generation uncertainty on market prices. For example, if forecast prices increase significantly under a higher demand scenario, it indicates that supply may be tight. Participants can mitigate their price exposure to such events by changing their generation offers, rescheduling generation outages or manging their flexible demand side resources.

(c) Review wind offers based on external forecast by system operator.

The system operator uses a commercial wind generation forecast in its internal security assessment processes. We worked with the system operator to publish the wind generation forecast and compare the market offers for wind generators.

This forecast allows participants to see whether wind generation offers submitted at the time are close to the wind forecast. It also helps wind generators to review their offers and ensure they are the best estimate of their potential generation.

The published wind forecast also includes confidence limits for that forecast. This allows participants to see when there may be periods of high uncertainty in wind generation output so they can plan their consumption and generation accordingly.

(d) Clarify availability and use of 'discretionary demand' control.

We made it mandatory for distributors to disclose how much discretionary demand they had available during a potential low residual situation via a 'difference bid' in the wholesale market. This means that both the system operator and participants have visibility of the resources available to manage the capacity risk. This results in more efficient allocation of

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[23] Electricity Authority. *Driving efficient solutions to promote consumer interests through winter 2023, consultation paper.* November 2022. Available at: https://www.ea.govt.nz/documents/1630/Driving_efficient_solutions_to_promote_consumer_interests_through_winter_2023.pdf

[24] A 'low-residual' situation is when the system operator notifies participants that the forecast schedules indicate periods with less than 200MW of generation remaining in the supply stack

resources and a broader market view of the impact that the resources committed have had.

Previously, only the system operator would have had any visibility of the discretionary demand available. This information was not available to the wider market, nor could the potential impact of those resources be seen in the forecast market schedules. This could lead to inaction by some participants as they were not sure if their resources were needed. This was particularly acute for slow-start thermal generation, as they faced significant costs in starting and synchronising a unit that may not actually be called on to generate.

We are starting to see new solutions for demand-side flexibility emerge

3.3. Responsibility for ensuring that sufficient firming capacity is available does not lie with one party in the wholesale market. All parties play a role in ensuring security of supply and good outcomes for consumers. Participants have a key role to invest in resources and contracting products to fulfil firming requirements for their consumers.

3.4. Alongside the traditional time-of-use pricing schemes employed by distributors to signal their sensitivity to network capacity issues to commercial and industrial consumers, we encourage the wider use of demand shifting tariffs to better manage demand peaks.[25] This issue is being discussed as part of the distribution pricing reform programme.

3.5. Retailers can signal the need for peaking or firming plant through supply contracts with generators. It is then incumbent on generators to ensure that they have sufficient capacity to meet their supply contracts. This would include the need to firm their own generation portfolio and allow for both planned and unplanned outages of their generation fleet.

3.6. Consistent with this approach, many participants have already started building flexibility portfolios in response to current market incentives and early adopters have started participating in the wholesale market. The examples below are an indication of emerging demand-side flexibility, some of which are already providing some benefit to the respective suppliers and consumers.

SolarZero winter 2023 flexibility trial

3.7. In July 2023 SolarZero started offering up to 30MW of aggregated domestic battery resources into the wholesale market using the dispatch notification product. The purpose of this trial was to prove the ability of aggregated domestic scale resources to respond to a dispatch instruction.

Meridian Energy commercial and Industrial flexibility contracts

3.8. In its recent investor briefing, Meridian announced it has 90MW of contracted demand response. This includes a 50MW arrangement agreed with New Zealand's Aluminium Smelter to reduce pressure on the system for 2023 and 2024 and a

[25] Electricity Authority. *Targeted Reform of Distribution Pricing, issue paper.* July 2023, 5. Available at: https://www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf

27MW deal with Open Country Dairy[26] available for both seasonal and peaking price volatility.[27]

Retailer consumer incentive offerings

3.9. Anecdotally, retail incentives, such as Contact's three hours of free power from 9pm to midnight, are also proving effective in moving consumption.

3.10. Genesis Energy offers customers on selected plans a Power Shout – the opportunity to book an hour of free consumption. Alongside this offering, access to load forecasts and electricity carbon intensity forecasts is provided to allow consumers to choose the best time for them to use the Power Shout.

3.11. Some retailers such as Flick Electric and Electric Kiwi are offering cheaper off-peak electricity to residential consumers. Electric Kiwi further enhances this offering with a free hour of power during off-peak periods.

Contact Energy supply deal with NZ Steel

3.12. Contact has entered an arrangement with NZ Steel to provide 30MW of renewable generated electricity for its $300 million Electric Arc Furnace in a flexible off-peak arrangement. Once the furnace is installed in 2026, the contract will enable NZ Steel to scale down production in times of winter peak demand or supply shortages.[28]

Meridian Energy southern green hydrogen project

3.13. Meridian also expects its Southern Green Hydrogen project to provide an additional 600MW of response. They may also develop up to 150MW of demand response as part of a suite of flexibility options in the wholesale power market.[29]

The Authority's work programme includes a suite of solutions to improve security of supply over time

3.14. Our work programme includes other initiatives that seek to address the impacts of the energy transition on electricity supply.

Short term – implemented in time for winter 2024/25

3.15. **Permanent implementation of winter 2023 measures** – we will permanently retain the following measures to address peak demand coordination issues:

(a) provide better information on headroom in the supply stack

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[26] Meridian. *Supporting the decarbonisation of Open Country Dairy*. October 2023, 30. Supporting the decarbonisation of Open Country Dairy | Meridian Energy

[27] Meridian. *Meridian / NZAS demand response agreement becomes unconditional*. June 2023, 8. Available at: https://www.meridianenergy.co.nz/news-and-events/meridian-nzas-demand-response-agreement-becomes-unconditional

[28] Contact. *Contact announces pioneering renewable energy agreement with NZ Steel*. May 2023, 21. Available at: https://contact.co.nz/aboutus/media-centre/2023/05/18/contact-announces-pioneering-renewable-energy-agreement-with-nz-steel#:~:text=Contact%20will%20provide%2030MW%20of,peak%20demand%20or%20supply%20shortages

[29] Meridian. *Meridian / NZAS demand response agreement becomes unconditional*. June 2023, 8. Available at: https://www.meridianenergy.co.nz/news-and-events/meridian-nzas-demand-response-agreement-becomes-unconditional

(b) provide forecast spot prices under demand sensitivity cases

(c) review wind offers based on external forecast by system operator.

The urgent Code amendment requiring distributors to disclose their available discretionary demand (clarify availability and use of discretionary demand' control) will expire in February 2024. We are consulting on a draft Code amendment to make this requirement permanent, ahead of winter 2024.[30] Consultation opened in December 2023.

3.16. **Dispatch notification enhancements** – following the successful implementation of the SolarZero winter flexibility trial, the Authority opened consultation on suggestions to enhance the dispatch notification product. The aim of these enhancements is to widen the ability for participants to use the dispatch notification product and lower barriers to participation. A decision on this work is due early 2024.

3.17. **Ancillary services review** – scoping of this work is underway, and the system operator will be engaged in early 2024 to start preliminary analysis and operational assessments. This analysis will focus on ensuring appropriate cost allocation for ancillary services and performance monitoring and reporting is in place. A further aim of this initial work will be to assess the frequency keeping ancillary service purpose and effectiveness.

3.18. **Survey of demand-side flexibility** - Given the importance of demand response to managing peak demand and the flow-on benefits to consumers, we are interested to further understand and quantify the level of available demand side flexibility. We have published a survey to seek information from industry on the availability of demand-flexibility resource. The survey will run in parallel to this consultation. The survey can be accessed at https://info.ea.govt.nz/sl/1b9596.

3.19. **Generation Investment survey** – the preceding 12 months have seen a significant shift in market conditions. This has been reflected in a reported increase in new connection requests to Transpower. With the changing investment environment, the Authority has refreshed its 2022 generation investment survey. We expect to publish the final results in early 2024.

Medium term – winter 2025 and beyond

3.20. **Wind generation forecasting improvements** – we recently consulted on changes to the arrangements for providing wind generation forecasts to the wholesale market. A decision on this work is due early 2024 and implementation of any changes will take place through 2024.

3.21. **Review of part 8 of the Code** – the Future Security and Resilience project has initiated a review of the common quality obligations set out in part 8 of the Code. This review aims to update connection and power quality standards to reflect the changing mix of generation technologies as we transition to a low carbon power system.

Long term – post transition to a low carbon economy

3.22. **Price discovery in a renewables-based electricity system -** the Market Development Advisory Group (MDAG) has been looking at the potential changes to

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[30] Electricity Authority. *Code amendment omnibus two*. December 2023. Available at: https://www.ea.govt.nz/documents/4321/Omnibus-2_consultation_paper_-_December_2023.pdf

the market that would be needed to support a renewables-based power system. The recommendations of this work were published in December 2023.[31]

Incentives for demand response

3.23. Supply contracts do not always directly incentivise consumers to respond to spot prices. However, there is generally an incentive on those companies selling the contracts to manage their spot exposure. This has traditionally been through the use of financial hedges or through the construction of generation to supply the electricity sold to consumers.

3.24. Recent advances in communication and control technologies have made the aggregated control of small-scale electrical devices more cost effective and granular. Using these resources to react to market prices to lower a consumer's exposure to the spot market is a good first step in proving the value of the technologies.

3.25. The full benefit to the participants, and ultimately consumers, will come from exposing that flexibility to the wholesale market.

3.26. Modelling has indicated that the unfettered uptake of demand-response is estimated to provide a total economic surplus of approximately $6.9 billion by 2050.[32] This surplus is broken down as a $2.8 billion consumer surplus and a $4.1 billion producer surplus.

3.27. By far the largest contribution to the total economic benefit from an uptake of demand-response will be in the offsetting of new transmission, distribution and generation investment – some $5.9 billion. The next largest contribution is estimated to be from the offsetting of thermal peaking plant, $0.347 billion.

3.28. The consumer surplus assumes that the benefit accrued to consumers in terms of reduced consumption and the financial benefits of ancillary service participation are fully realised and passed through to them.

3.29. The key to unlocking this benefit is opening existing ancillary service markets to demand response and distributed energy resources (DER) and ensuring that the participation of these resources is fully considered in the design of any new services that may be needed in the future.

3.30. In the shorter term, relatively small quantities of demand response at peak demand periods can have a meaningful impact on spot prices. Analysis of the generation offer stack for June to September 2023 shows that, on average, a modest reduction of demand at peak[33] could reduce wholesale prices by $11.58/MWh (7%) for a 20MW reduction, to $31.33/MWh (19%) for a 50MW reduction (Table 1).

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[31] MDAG. *Price discovery in a renewables-based electricity system*. December 2023, 11. Available at: https://www.ea.govt.nz/documents/4335/Appendix_A2_-_Final_recommendations_report.pdf

[32] Sapere. *Cost-benefit analysis of distributed energy resources in New Zealand*. September 2021, 13. Available at: https://www.ea.govt.nz/documents/1742/Sapere_CBA.pdf

[33] Trading periods 16, 17, 36, 37 and 38.

Table 1: Monthly and overall average marginal price of electricity, marginal price sensitivities, and Benmore and Otahuhu spot price ($/MWh)

		Benmore	Otahuhu	Base case	20MW Less Demand	50MW Less Demand
Daily Peak Average	June	$222.56	$280.73	$227.15	$194.32	$136.68
	July	$125.54	$148.68	$132.39	$128.19	$122.08
	August	$154.96	$187.73	$164.31	$158.58	$147.62
	September	$116.89	$144.82	$130.88	$126.85	$121.83
	Overall	**$154.75**	**$190.13**	**$163.43**	**$151.85**	**$132.10**

3.31. Table 2 summarises the current incentives implied by different electricity supply contract forms. This demonstrates that, irrespective of supply contract form, either the consumer or the supplier will have an incentive to manage their exposure to high spot prices.

Table 2: Summary of current incentives implied by different electricity supply contract forms

Contract type	Incentives	Implication
Variable $/kWh, variable volume	Spot price exposure – consumer prices reflect the cost of supply.	Consumers have correct incentives to adjust demand to price. No further payment for demand response (in addition to the variable price saved).
Fixed $kWh, variable volume	Consumer prices may not reflect the cost of supply in real time. Time-of-use pricing is more cost-reflective but will not perfectly match costs in real time, especially at times of scarcity. Suppliers (generators or retailers) are exposed to the difference between	Consumers have no incentives to adjust demand. But retailers have an incentive to pay for a demand response to minimise losses from buying at a high spot price and supplying at a lower contract price.[34] Payment for demand response would be some share of the difference between spot price and the fixed $/kWh. (The consumer would save on the cost of the fixed $/kWh).

[34] This is an alternative or a complement to financial hedging and could be targeted to very high-priced times. Such incentives exist for gentailers and non-integrated retailers when spot prices exceed retail tariffs – whether or not they get supplied at wholesale market spot or contract prices, as all parties have an incentive to reduce lower earning consumption to re-sell into the higher earning spot market.

	market and contract price instead. Some consumers will be more price-responsive than others.	The inducement would need to be big enough so that it plus avoided retail charges compensate consumers for foregone benefits from electricity use.
Variable $/kWh, Fixed volume	Spot price exposure – consumer prices reflect the cost of supply. Consumers must take (are liable for) the contracted volumes at the market price.	Consumers have incentives to adjust demand to price but must buy the contracted volumes. A consumer can re-sell surplus volumes where market prices exceed the value of the electricity to that consumer. On a net basis, the consumer does not receive a payment for demand response, assuming that the resale price would be similar to the variable price they would have to pay.
Fixed $/kWh, fixed volume	Consumer prices may not reflect the cost of supply in real time. Consumers must take (are liable for) the contracted volumes at the agreed price.	Consumers must buy the contracted volumes. It is only when spot prices exceed the fixed contract price *and* the value of electricity to the consumer that they have an incentive to adjust use and re-sell surplus volumes at the spot price (for the duration of the contract). The payment for demand response is then the difference between spot and fixed contract prices.

3.32. Active participation by demand in the wholesale electricity market is increasing but still underdeveloped. There have been suggestions to develop a paid demand response scheme to promote participation, as seen in some overseas jurisdictions.

3.33. As we discuss later in this paper, a number of those schemes were implemented to address participation shortcomings for the demand side in those respective markets. With the implementation of dispatchable demand and dispatch notification in the New Zealand market in May 2023, there are no such technical barriers.

3.34. At a basic level, there is no strong rationale to pay a consumer who buys from the spot market for reducing consumption. The market price provides a signal to consumers on when it is most efficient for them to consume electricity. This can be directly, in the case of spot price exposed consumers or indirectly through their electricity tariff, as described in Table 2 above.

3.35. Paying consumers not to consume risks distorting this incentive away from the productive and efficient use of electricity. A payment could overcompensate that consumer, and lead to a larger-than-efficient demand response.[35] This would further distort the spot price signal to invest in further generation, impacting the longer-term efficiency and security of supply outcomes of the wholesale market. Such a scheme would not be for the long-term benefit of consumers.

Q2: Do you agree with our assessment of the incentives for demand response participation in the wholesale market? If not, what is your view? Are there other criteria that the Authority should consider?

Q3: Other than financial incentives, what are the other barriers to entry for demand response participation in the wholesale market that you have identified?

4. The Authority considers it best to focus on improved market participation for demand response and BESS in the short-term

4.1. The Authority considers the underlying cause of the occasional mismatch between demand and generation resources at peak times is an investment timing issue. The Authority will continue to monitor the peak capacity available to the market. Should an unexpected issue arise, we will assess the need for intervention at that time.

4.2. In the long-term, this mismatch can only be solved with more investment in controllable generation capacity, energy storage or more price-responsive demand control.

4.3. In the immediate future, BESS and demand response are the most likely source of new flexible capacity. We acknowledge that there are some challenges associated with broader participation of BESS due to the ability to operate as both a load (charge) and generator (discharge) and associated market and market systems limitations.

4.4. Current market system modelling does not easily integrate such characteristics in a single asset and can lead to limitations on participation in some markets. The most notable of these is the frequency keeping ancillary service. Currently a BESS could only participate when discharging ie, acting as a generator, whereas it may also be technically capable of participating when charging. This limits the potential revenue available to the BESS operator and weakens the business case for investment.

4.5. Similarly, the only New Zealand market ancillary service that the demand side can participate in is the instantaneous reserve market. We note that the Australian national electricity market (NEM) includes demand side participation in both the contingency, equivalent to our instantaneous reserve market, and the regulation, equivalent to frequency keeping, products of the Frequency Control Ancillary Service (FCAS). Further investigation of the challenges, benefits and likely

[35] This is one of the key design flaws of so-called nega-watt schemes, which treat a megawatt of demand reduction as equivalent to a megawatt of extra generation. This is true from a physical market-balancing perspective, but they are not equivalent from an economic perspective. Generators use resources and incur costs to produce a megawatt. Consumers save their resources for another use when they do not use a megawatt. The other key flaw is not having an objective, verifiable measure of demand response, that is how much a consumer would have consumed in absence of the payment.

participation rates for demand side participants in the frequency keeping market may be warranted.

4.6. In the near term, we consider that the Authority's efforts are best focused on checking for and removing any regulatory roadblocks to investment and innovation in BESS and in demand flexibility services. This includes ensuring that these resources can easily participate in existing ancillary service markets. This is discussed in more detail in the following sections.

BESS offer structure

4.7. Under current market rules, BESS must offer as a generator when discharging and bid as dispatchable demand load when charging. This allows the BESS to participate in the instantaneous reserve market as a generator when discharging and an interruptible load provider when charging.

4.8. However, the market system currently cannot model a resource that can transition from load to generation – each state is modelled separately. While this may not always cause issues, it is possible that the BESS could be dispatched for interruptible load provision while being dispatched to 'generate' at the same time. This would need careful management by the provider to ensure that their market offers were consistent and that dispatch instructions received were consistent.

4.9. A way to improve this may be to introduce a 'bi-directional' offer form for BESS. This would be structured much like the current difference bids used in the forecast market schedules.

4.10. From a central position of neither charging nor discharging, the BESS participant would be able to signal the various price bands that they would be willing to charge or discharge. As the charge and discharge states would then be modelled in a single offer, an instantaneous reserve offer could be provided that reflected the total change in state the BESS can achieve.

4.11. This would remove the risk of inconsistent combinations of energy and instantaneous reserve being dispatched. It may also simplify the offer formulation for BESS operators and make it more efficient to manage their resource.

Dispatchable demand enhancements

4.12. For those participants that may be able to bid dispatchable demand into the wholesale market, there remain some operational concerns regarding how their plant may be dispatched.

4.13. One concern is regarding the potential to be dispatched back on too soon after being dispatched off. A number of industrial processes take time to shut down and must remain off for a period before they can be restarted. This means that they cannot change state too quickly.

4.14. At present, this cannot be accommodated in the dispatchable demand regime. One possible enhancement may be to introduce a 'return time' constraint to dispatchable demand. This would allow a participant to signal to the system operator a minimum return time from their dispatch off. This return time could be applied in the form of a dispatch limit constraint that is automatically applied when the dispatchable demand participant is dispatched off. The constraint would apply for a fixed number of trading periods before the participant could be dispatched back on.

4.15. Bid dispatch currently assumes that demand can move completely between different levels of consumption within the dispatch period, no allowance is able to be made for safe shut down and re-start procedures. This may be causing dispatch compliance concerns among potential participants. One possible solution could be to include ramp rates to dispatchable demand bids, in the same way that generators include ramp rates in their offers. This would allow participants to reflect any operational procedures that would limit their ability to affect a dispatch instruction within the 5-minute dispatch period.

Wider Authority work programme

4.16. As discussed in section 3 of this paper, the Authority already has a significant work programme in place that is seeking to enhance participation for flexibility providers, foster innovation and ensure that new technologies can participate effectively.

4.17. **Ancillary services review** – scoping of this work is underway and the system operator will be engaged in early 2024 to start preliminary analysis and operational assessments. This analysis will focus on ensuring appropriate cost allocation for ancillary services and performance monitoring and reporting is in place. A further aim of this initial work will be to assess the frequency keeping ancillary service purpose and effectiveness.

4.18. **Wind generation forecasting improvements** – we recently consulted on changes to the arrangements for providing wind generation forecasts to the wholesale market. Implementation of any changes will take place through 2024.

4.19. **Review of part 8 of the Code** – the Future Security and Resilience project has initiated a review of the common quality obligations set out in part 8 of the Code. This review aims to update connection and power quality standards to reflect the changing mix of generation technologies and to remove technical barriers to entry as we transition to a low carbon power system.

4.20. **Multiple trading relationships trial –** we have approved two exemptions and amendments to the Code to allow for a trial to take place and test energy sharing across selected Kāinga Ora housing.[36] The aim of multiple trading relationships is to give consumers more choice and flexibility about how to use the electricity they produce and consume.

4.21. **Access to data and information** – work is underway to enable distributors and others to better see what is happening on the low voltage network and drivers of congestion.[37] This information, along with Default Distributor Agreements (DDA), will support distributors to facilitate the uptake of flexibility services, including services provided by non-retailer aggregators.

4.22. **Price discovery in a renewables-based electricity system -** MDAG has been looking at the potential changes to the market that would be needed to support a renewables-based power system. The final recommendations of this work were published in December 2023.

[36] Electricity Authority. *Solar energy sharing for social housing trial.* June 2023, 27. Available at: https://www.ea.govt.nz/news/general-news/solar-energy-sharing-for-social-housing-trial/

[37] Electricity Authority. *Updating regulatory settings for distribution networks*. Available at: https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/

Investment is already happening

4.23. As discussed in Appendix A, Transpower's latest six-monthly monitoring report indicates a significant level of interest in BESS. This is both as stand-alone, grid-scale, systems and as complements to solar generation investments.

4.24. At present, the participation methods for BESS in the wholesale market are complex. The participant is required to provide demand bids for times the resource is charging, and separate energy offers to signal discharge periods. If the participant also aims to offer into the instantaneous reserve market, then the type and quantity of reserve they can offer will be limited by whether they are charging or discharging at the time.

4.25. Simplifying the offer process and requirements may make it more appealing for BESS and enable new revenue streams to support the business case for further investment.

4.26. We note that the NEM's frequency control ancillary service (FCAS) divides its services into up and down regulation services, both of which are explicitly open to demand side participation. Further engagement with the AEMC will be needed to determine the level of participation of demand side resources in the FCAS market.

Further investigation and consultation is needed

4.27. Further enhancements to participation should be driven by power system needs and resource capability. Changes to participation paths for demand side and BESS resources will require changes to the system operator's market tools. The cost and time frames involved should be balanced against the expected benefits when considering prioritisation of those options.

4.28. We consider that participants should manage their own risk through voluntary participation in the various market mechanisms. The developments highlighted earlier in this paper demonstrate that some participants are valuing demand side flexibility as a cost mitigation tool but have yet to take the step of signalling this value in the wholesale market.

4.29. Given the broader system security benefits of improved coordination, the Authority could also consider making it mandatory for participants with contracts for demand side flexibility to signal their resources in the market. This could align with the current obligations on generators above 30MW to need to offer into the market. Aggregate quantities of contracted flexibility could be required to bid in the market and be subject to similar dispatch compliance obligations. This would not be a preferred option at this time.

4.30. Coordination with the Authority's wider work programme is essential to ensure any enhancements are complementary.

Q4: Do you agree that the Authority should focus its resources on identifying and lowering barriers for BESS and demand side flexibility to participate in the wholesale and ancillary services markets? If so, where do you think the Authority should focus first?

5. Options to better manage supply risk for winter 2024 and beyond

5.1. Despite the confidence in the growing amount of available demand response and BESS, the Authority is mindful of the disruption a significant outage could cause. We appreciate the importance of confidence in security of supply to consumers and will continue to closely monitor the situation. We will carefully consider the need to intervene should the need arise while more flexible resources come to market. This is a delicate balance as the risk of unintended consequences is high.

5.2. In our decision paper on *Driving efficient solutions to promote consumer interests through winter 2023*,[38] we noted some potential solutions that could not be implemented in time for winter 2023, but that warranted further investigation.

5.3. The purpose of this consultation is to seek views on:

(a) a new integrated ancillary service to offset increased uncertainty in net demand as a potential long-term solution[39]

(b) some interim options to manage the security of supply risk for winter 2024 and winter 2025

(c) the Authority's proposed path to investigate potential barriers for the full and efficient participation of demand response and BESS in the wholesale market.

5.4. We have used observations from winter 2023 and our preliminary assessment of the outlook for winter 2024 and winter 2025 to inform these options.

5.5. Based on this information, our review of international experience, and the emerging market appetite to explore demand side solutions, we believe that an interim option may not be required at this point in time.

5.6. We also consider that while further analysis into an integrated ancillary service is useful, it too may not be required.

5.7. These views are discussed in more detail below.

We consulted on evaluation criteria in our winter 2023 peak supply management consultation

5.8. As a part of our *Driving efficient solutions to promote consumer interests through winter 2023* consultation, we proposed a set of evaluation criteria to use in assessing potential options.[40] Following feedback, we refined and confirmed the evaluation criteria as:

(a) improve the information available to customers and operators to make efficient contracting and commitment decisions

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[38] Electricity Authority. *Driving efficient solutions to promote consumer interests through Winter 2023, decision*. March 2023. Available at: https//www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

[39] Option F from the Winter 2023 consultation.

[40] You can find more information on these alternative and additional criteria at: Electricity Authority. *Driving efficient solutions to promote consumer interests through Winter 2023, decision*. March 2023. https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

(b) better align the incentives on purchasers and operators with the interests of end-use consumers

(c) minimise the risk of unintended harmful side-effects for consumers, such as weakening current incentives to invest in flexibility resources, contract to provide flexibility, or undermining confidence in the market

(d) be able to be modified or removed if they do not provide net benefits, and ideally act as an enabler for future solutions or lead to enduring solutions

(e) align with net zero by 2050 target[41]

(f) can be implemented for winter 2023

(g) meets the Authority's statutory objective.

5.9. For the assessment of the need for a standby ancillary service, either as a permanent integrated product or as an interim product, we propose using the same evaluation criteria, with the exception of criterion (f). For the interim solutions, we consider whether policy changes could be implemented by winter 2024.

5.10. The implementation of an integrated standby ancillary service would be a multi-year project. This paper presents the first stage of that work for industry consultation. We have considered options for implementation and conducted a survey of similar schemes implemented in other jurisdictions.

5.11. As we discuss in section 7, were we to progress with the implementation of a market integrated solution, it would likely require a further two to three years of policy design and consultation before actual implementation could start given the scope and consequences of such a change.[42] Given the scale of change that would be required to market operation service provider systems, it is likely that the related system changes would also be of the scale of a multi-year project.

Q5: Do you agree that any solutions should satisfy these principles? If not, what is your view and why? Are there other principles that the Authority should consider?

6. Financial incentives to provide flexibility

6.1. The financial hedging market, hosted on the Australian Stock Exchange (ASX), currently trades 'peak' futures products alongside baseload products. These peak futures products allow participants to purchase contracts for electricity that provide cover between the hours of 7am and 10pm on business days. The MDAG report recommends the development of 'new flexibility products (standardised)' (recommendation 8).

6.2. An example of such a flexible product is the NEM's 'super peak swap' product. This product is designed to provide cover during high demand periods during the morning and evening peaks but provide no volume cover during the lower demand middle of the day. This would allow flexible supply and demand side flexibility to

[41] Noting that the '100% renewables by 2030' strategy is a governmental aspiration for the industry.

[42] As described in appendix B, the AEMC undertook 3 years of policy design and system modelling work before proposing not to progress with an integrated standby ancillary service for the NEM. Similar levels of analysis would likely be needed to ensure that any design does not negatively impact market incentives and operation.

participate in the forward price discovery process and obtain more certain revenues while supporting the management of peak demand.

6.3. A further recommendation, recommendation 24, proposes enhancing price discovery through mandated market making for these flexibility products. In this paper we ask whether there is a case for accelerating the introduction of market making obligations to further support the development of flexible resources in the wholesale market.

6.4. The Authority proposes to start investigation of the design considerations for such a financial product with an industry workshop in early 2024. Issues to be consider include, but are not limited to:

(a) Incremental product volumes,

(b) Seasonal adjustment of product specifications,

(c) Bid ask spreads,

(d) Market making requirements

6.5. We welcome your further input on other considerations.

Q6: Do you agree that a standard product for financial ‘super peak’ hedges is required?

Q7: What factors do you think we should consider in the design of such a product?

7. Considering the need for an Integrated Standby Ancillary Service

7.1. In our decision paper on *Driving efficient solutions to promote consumer interests through winter 2023*, we decided not to progress the implementation of a standby ancillary service for winter 2023 because it would not have been possible to ‘operationally integrate’ a new ancillary service in the time available.

7.2. We noted that, following winter 2023, we would prioritise investigation of a new integrated ancillary service for standby reserve as a possible long-term solution to better manage supply risk.[43]

7.3. We emphasised that this new ancillary service for standby reserve should be:

(a) fully integrated into the spot market (like other ancillary services, such as frequency keeping and instantaneous reserves) to ensure additionality

(b) technology agnostic and neutral between demand and supply flexibility to favour market competition.

[43] In previous years, the Market Development Advisory Group (MDAG) and the Ministry of Business, Innovation and Employment (MBIE) have also recommended investigating the creation of a new integrated ancillary service for standby reserve. The MBIE report into 9 August 2021 demand management event recommended implementing an ancillary service to address ‘multi hour shortfalls’. MDAG’s recommendations are part of its work programme to ensure economically efficient price signals under a 100% renewable electricity supply. The most relevant to this consultation are:

- Option A4: Creating a new reserve product to cover sudden reduction from intermittent sources. This was a preferred option, and
- Option C10: Creating a procurement process for high-scarcity demand side flexibility (DSF). This was a partially supported option.

Box: Driving efficient solutions to promote consumer interests through winter 2023 - Analysis of submissions

Option F – a new integrated ancillary service

Timing was a key issue for the implementation of Option F. Several submitters disagreed, or doubted, that this option could have been implemented by winter 2023 in a manner that did not compromise its potential long-term benefits. Most of these submitters supported development of an integrated ancillary service as a longer-term option, post winter 2023. Only a few submitters clearly supported the investigation of an integrated ancillary service for winter 2023.

The system operator procures ancillary services to manage system security

7.4. The system operator currently has arrangements in place to procure five ancillary services to support system security management:[44]

(a) **Frequency keeping** – balances generation and demand as generation responds to dispatch instructions and demand varies

(b) **Instantaneous reserve** – arrests the fall of grid frequency following a sudden loss of generation or transmission and quickly restores frequency to its normal operating band

(c) **Over-frequency arming** – manages grid frequency following an event that causes frequency to rise above security limits

(d) **Voltage support –** supports maintaining localised transmission voltage levels within specified limits, and

(e) **Black start** – maintains equipment that can initialise the supply for progressively restoring the grid following a partial or total blackout.

7.5. Only two of these services are required to be dispatched alongside the energy market: frequency keeping and instantaneous reserve.

7.6. This reflects the dynamic nature of the system risk being managed and the integrated nature of the resources providing those services. That is, both these services can be provided by generation that would otherwise be supplying energy into the wholesale market.

7.7. Demand side participants can also provide instantaneous reserve in the form of interruptible load – demand that can be disconnected automatically in response to a significant fall in grid frequency.

7.8. The remaining ancillary services are procured on a tender basis, as described in the system operator's ancillary services procurement plan. Their use is dictated by real time or forecast grid conditions, but their use does not necessitate their integration with the wholesale market.

[44] The specification and procurement arrangements for each service are detailed in the system operator's ancillary services procurement plan (Electricity Authority. *Ancillary services procurement plan.* March 2022, 22. Available at: https://www.ea.govt.nz/documents/918/Certified_copy_of_document_-_ancillary_services_procurement_plan_-_3_May_2022.pdf).

Standby reserve is spare capacity that acts as a buffer against large changes in the system

7.9. This paper considers the need to procure standby reserve as an additional ancillary service. Standby reserve is the capability to respond to large, unexpected, changes in energy requirements. Minimum levels of standby reserve are required for the system operator to maintain system security and reliability. Standby reserve or 'headroom' can be measured in forecast and dispatch schedules as offers of energy available once energy, reserve requirements and frequency keeping requirements have been considered.

7.10. Instantaneous reserve is intended to replace lost supply following the sudden loss of a significant generator or transmission circuit. Standby reserve could be considered a replacement for a more gradual loss of supply, such as when a wind generator reduces output in response to a drop in wind speed.

7.11. Frequency regulating reserve[45] is intended to maintain the frequency in near real time[46] within limits that are set to ensure power system security. Maintaining system frequency within set limits is the responsibility of the frequency keeper. The frequency keeper is required to manage relatively small variations in energy requirements (eg, +/- 30MW). However, our current frequency keeping ancillary service is not specified to manage large, unexpected changes in energy requirements.

Integrated resources can be offered into both the ancillary service and the spot markets

7.12. Being integrated into the spot market means that resources can be offered into both the ancillary service market and the spot market. They would then be divided between each market depending on the lowest overall costs (this is known as co-optimisation). This would be similar to what happens for the procurement of other ancillary services, such as instantaneous reserve and, to a lesser degree, frequency keeping.

7.13. This means that the least-cost combination of resources can be allocated to the energy and ancillary services market automatically. As with energy instantaneous reserves at present, the market system can vary the dispatched resources to ensure that overall costs to consumers is minimised when taking into account the complexities of New Zealand's transmission network and the operating limitations of the various resources offered into the market.

7.14. Integrating a standby ancillary service into the spot market would bring that capacity into the energy spot market. This would separately value the availability of flexible, responsive resources, and in doing so provide an explicit signal for their provision.

7.15. Full integration would allow for efficient, least-cost allocation of resources as well as the provision of efficient price signals.

How would a new standby ancillary service work?

7.16. When considering what form a potential integrated standby ancillary service could take, a key consideration is how it would interact with the current wholesale market

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45 Provided by the frequency keeper(s).

46 In between dispatch instructions.

tools and settings. This section sets out a potential model for how such a service could work, and the complexities involved with designing it.

7.17. Participants would bid (demand-side) or offer (supply-side) their resources into the market. Separate bids and offers would be made for the energy market, the instantaneous reserves market and the standby reserves market. Each bid and offer would come with bid/offer prices and quantities to reflect their preferences.

7.18. The Scheduling, Pricing and Dispatch (SPD) tool would determine the overall least-cost allocation of energy (to ensure supply meets demand), instantaneous reserves (to meet the largest risk on the system) and standby reserve (to meet the residual requirement).

7.19. The residual requirement could be set at an operational setting of 200MW, reflecting the current trigger for a low residual situation notice set by the system operator. Alternatively, it could be calculated in a more dynamic manner to take into account system conditions. For example, when wind offers vary significantly from the wind forecast, the residual requirement may be increased.

7.20. Like instantaneous-reserves providers, providers of standby reserve would be expected to have their resource on standby and to respond, if called upon by the system operator.

7.21. Payments would be made to standby reserve providers for any ‘cleared’ standby reserve. That is, payment is made for the reserve on standby, regardless of whether it is called upon by the system operator. The payment would be determined by the price of the standby reserve (for each trading period) multiplied by the quantity of the standby reserve (for each trading period). Both the price and the quantity would be determined by SPD.

7.22. We would need to further investigate the appropriate cost allocation for this service. Costs could be allocated across all purchasers as the main beneficiaries of the service. Alternatively, costs could be allocated to generators as the causers of the need for the service. However, we note that ultimately consumers will likely bear the costs through direct allocation of the costs or indirectly as a pass-through cost from retailers.

7.23. SPD is a linear optimisation model and seeks to optimise outcomes by attempting to minimise total cost given the physical limitations of the power system. These physical limits are known as ‘constraints’. SPD needs to have a constraint violation penalty for each scenario where it may need to ‘break’ or ‘violate’ a constraint to ensure the model can return a solution.

7.24. Our current market has constraint-violation settings for energy scarcity situations, as well as for reserve scarcity situations (for both insufficient fast instantaneous reserves and insufficient sustained instantaneous reserves). The constraint-violation penalties are specified in clause 13.58AA of Code and are summarised in Table 3:

Table 3: Current violation settings for energy and reserve scarcity situations

Tranche	Energy contingent risk violation ($/MWh)	Quantity
1	10,000	For the first 5% of demand
2	15,000	For the next 15% of demand
3	20,000	For the remaining 80% of demand

Tranche	Fast instantaneous reserve contingent risk violation ($/MWh)	Sustained instantaneous reserve contingent risk violation ($/MWh)	Quantity (MWh)
1	3,500	3,000	50
2	4,000	3,500	100
3	4,500	4,000	No limit

7.25. When determining the appropriate constraint violation penalty for standby reserves, we need to consider where the value should sit in relation to the constraint violation penalties for energy and instantaneous reserves. The scarcity prices for each of these products should reflect the value of the product (to maintaining system security) and the correct order that the products are expected to respond, if there is a shortfall of energy.

7.26. The purpose of standby reserve is to restore the residual when the system operator determines that the residual is low. In the case of a grid emergency when forced demand curtailment is required, the system operator would first restore any shed demand. Then they would restore any instantaneous reserves to ensure system security. Finally, they would restore the residual (or buffer against any further loss).

7.27. It follows that the constraint violation penalty for standby reserves should be priced lower than the penalty for sustained instantaneous reserves. That is, the constraint violation price for standby reserves should be less than $3,000/MWh.

7.28. For example, the constraint violation penalty for standby reserve could be set at $2,500/MWh. It may even sit lower, if it is determined that there should be more than one tranche for the scarcity values. This value seems quite low when compared with the potential value of demand and the value of generation that is typically at the top of the offer stack. Hence, the introduction of a fully integrated standby ancillary service may require all scarcity values to be reviewed.

Potential benefits

7.29. Establishing a new fully integrated standby ancillary service would allow for a more efficient, potentially lower cost and transparent allocation of resources while supporting efficient price signals in the wholesale market. It could provide greater visibility of the available resources to market participants and assist with mitigating risk.

7.30. With careful design, a new service could support power system resilience by incentivising investment in flexible dispatchable resources, and reward resources that regularly provide reserves to the market but are infrequently dispatched for energy.

7.31. The technology-agnostic nature of the design would allow the new ancillary service to promote competition in the new market.

7.32. It could also encourage participation of demand side resources in the wholesale market by providing an additional revenue stream for the demand side (similar to the mechanism for interruptible load availability payments).

Potential disadvantages

7.33. The potential cost to consumers would require more detailed investigation before a decision could be made to implement such a scheme. Ultimately, the potential benefits associated with improvements to system security and reliability would need to be weighed against the likely costs to consumers.

7.34. Such a service would be designed to support power system resilience. However, we note the unintended consequences experienced internationally with the design of such schemes and the potential significant pitfalls of a hurriedly designed solution (see Appendix B).

7.35. Notwithstanding the time needed to develop a policy design for such a product, integration with the current market system would not be an insignificant undertaking. This paper represents the Authority's initial work in assessing the need for a service and considering implications on incentives within the wholesale market.

7.36. If we were to continue with this work, it is likely that a further one to two years of policy development, consultation and modelling would be required before implementation of these changes could start with our market service providers. Recent experience with projects such as real-time pricing suggests that this implementation could add a further one to two years on the implementation timeline.

7.37. We therefore consider an integrated standby ancillary service to be a medium to long-term solution, and not a potential solution for winter 2024.

An integrated ancillary service may not offer the expected improvements while adding costs for consumers

7.38. We expect residuals to be tight over the next few years as we progress through the energy transition. However, we may not need a product for standby reserve in the long term if there is sufficient flexibility from batteries and demand-response to see us through this period.

7.39. In the long term, we expect issues with tight residuals to ease. This is due to several factors including:

(a) greater technological and geographic diversity of intermittent generation

(b) improvements in intermittent generation forecasting capabilities

(c) an increase in firming generation capacity, storage capacity and demand response

(d) retirement of slow start thermal generation, eliminating the unit commitment problem.

7.40. These factors can limit the frequency and impact of unexpected events and, therefore, reduce the impact of any variability of power system conditions. The winter peak capacity coordination issue is a characteristic of the transition to a low-emissions economy and is unlikely to persist long term due to investments in generation, storage, and load management, and an increased understanding of market operations in a highly-renewable power system.

7.41. The Authority is continuing to monitor these changes through our existing work programme. Our now annual survey of the generation investment pipeline provides good information as to the intent of participants to invest, including the location of and the generation proposed to be built. The Future Security and Resilience project is monitoring and assessing thermal generation retirement plans and their likely impact on reliability.

7.42. Transpower, as grid owner, has recently updated its grid connection query portal to clearly indicate the location, stage, capacity and timing of grid connection queries.[47]

7.43. A standby reserve market is not primarily designed as a tool to provide long-term investment signals. Hence, there is a risk that such a market may dilute investment signals generally, particularly for fast-start plant. Furthermore, even signalling a long-term solution for an integrated standby ancillary service could discourage demand-response innovation in the near-term.

7.44. Overall, a new scheme may not offer any security improvements relative to current arrangements. Standby reserve would primarily come from flexible sources that are already being offered to the market under the current regulatory regime. This would introduce additional costs for consumers while resulting in no net-gain in system security. This outcome is supported by the experiences in both the Texas market and the NEM, as described in section 8 and Appendix B.

7.45. Therefore, on balance, we expect the benefit of any integrated ancillary service would be short lived once the likely design and implementation timeframes were allowed for.

AEMC standby ancillary service consultation

7.46. In 2020 the Australian Energy Market Commission (AEMC) consulted on the introduction of an operating reserve market to help respond to unexpected changes in supply and demand.[48] In December 2023, they made a draft determination not to progress this option[49] because it would not offer any material performance improvements relative to the current arrangements while introducing additional costs for the market.

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[47] Transpower. *New Connection Enquires.* Available at: https://experience.arcgis.com/experience/97d4604079b545448280423f9269b9ea/page/Dashboard/

[48] This would be similar in nature to a market integrated standby ancillary service.

[49] AEMC. *National Electricity Amendment (Enhancing reserve information) Rule 2024.* December 2023, 21. Available at: https://www.aemc.gov.au/sites/default/files/2023-12/Enhancing%20reserve%20information%20-%20draft%20determination.pdf

7.47. AEMC modelling shows that 'a fleet that evolves to firm renewables with very flexible storage technologies:

   (a) will likely be well-placed to manage net demand uncertainty in operational timeframes (five minutes to an hour) so long as participants have sufficient storage to account for such uncertainties

   (b) should be reasonably well-placed to manage net demand needs over the course of a full day, so long as sufficient depth of charge and other resources are available to manage the potential for longer duration events to occur.'[50]

7.48. We consider that the AEMC's rationale can be applied to the New Zealand context. There is evidence of highly flexible resource in New Zealand's investment pipeline,[51] such as BESS and demand response, that can respond quickly to energy gaps in the operational timeframe.

7.49. The AEMC is instead focusing on two additional incremental improvements:

   (a) develop and publish more information on energy availability to the market

   (b) procure frequency control ancillary services at a regional level.

7.50. These improvements provide the opportunity to observe the future fleet's response to changes in market signals, before introducing any complex changes.

Q8: Do you agree with our assessment of the risk for the medium to long term?

Q9: Do you think it would be beneficial to create a new integrated standby ancillary service? What is your view and why?

Q10: How should the costs for a standby ancillary service be allocated?

Q11: How should the residual requirement be set? Should it be an operational setting or dynamically calculated? If it is dynamically calculated, what factors should be considered in the calculation?

Q12: How should deficit (scarcity) standby residual be priced in relation to scarcity energy and scarcity reserve prices?

8. Interim options to manage residual security of supply risks

8.1. We have also investigated interim options for implementation by winter 2024. These options are intended to both support security of supply and accelerate the uptake of demand-response.

8.2. Batteries and demand response are the most likely source of new flexible capacity in the short term. They are generally cheaper and less complex to implement than an equivalent capacity of generation. We believe that focusing on solutions to

[50] AEMC. *National Electricity Amendment (Operating Reserve Market Directions Paper) Rule*. August 2023. Available at: https://www.aemc.gov.au/sites/default/files/2023-08/directions_paper_2023_0.pdf

[51] Discussed in Appendix A

enhance participation of demand response and BESS will alleviate the challenges with meeting peak demand in both the short term and the longer term.

8.3. We also recognise that capacity supply issues can arise through the unexpected loss of resources, such as an unplanned outage of a significant generator. In these circumstances, it may be prudent to implement a temporary solution while market participants respond to the issue. Ideally, these short-term solutions would provide an additional incentive for participants to expose their flexible resources to the wholesale market. This would lead to more efficient pricing outcomes and better operational visibility for the system operator.

8.4. A key consideration is whether current demand side incentives and any solutions to enhance the participation of demand response and BESS will incentivise the development of these solutions in a timely manner to meet the challenges for winter 2024 and 2025.

8.5. These interim options fall into two broad categories:

(a) contracts for out-of-market resource

(b) incentives for providers to commit their resources to the wholesale market.

8.6. Table 4 provides a summary of the options that have been identified and our initial evaluation of these options against the principles outlined in section 5.8.

8.7. Our preliminary assessment is that an interim option may not be required. More information on each of the options and our preliminary assessment is presented further below.

Table 4: Interim options for winter 2024 and winter 2025

Option	Improves information	Aligns with consumer interest	Limits unintended consequences	Can be modified	Aligns with net zero by 2050	Meets statutory objective	Policy changes implementable by winter 2024
Option 1: contracts for out of market resource	N	N	N	N	N	N	**Y**
Option 2: Out-of-market tender for emergency demand response	N	N	N	N	**Y**	N	**Y**
Option 3: Provide payments to participants to commit their resources to the market							
Variation (a) **Pay for the 200MW residual**	N	N	N	N	N	**Y**	**Y**
Variation (b) **Pay for *all* available residual capacity**	N	N	N	N	N	N	**Y**
Variation (c) **Pay for all available residual capacity – dispatchable demand only**	**Y**	**Y**	N	N	**Y**	**Y**	**Y**

8.8. When assessing whether an option can be implemented in time for winter 2024, we note that this refers to the policy changes needed to implement the option. The impact of changes required to service provider systems, such as the Clearing Manager's payments system or the system operator's market modelling of dispatchable demand participants, are unknown and would need to be confirmed once the scope of any changes is fully understood.

8.9. Additionally, participants would likely need to make significant changes to their control systems and operational processes. These changes would further limit the speed with which an option could be implemented.

8.10. We note that all options would result in increased costs to consumers through the need to procure an additional service. All options would also require a Code amendment to allocate the costs of a new service. We also note that while a solution can be intended as temporary or short-term, for instance by including 'sunset' clauses in the Code, removing the scheme can be very difficult once a payment regime is put in place and participants include it in their risk management approach.

8.11. Once participation based on revenue from an interim solution has started, there will be pressure from the providers to maintain the service beyond the sunset date even if the value to the power system has reduced below the cost of providing the service. This pressure could be particularly acute if the additional resilience benefit delivered by the product has been factored into security of supply assessments.

Option 1: Contracts for out-of-market resource

8.12. Separate payments outside the spot market could be used to encourage providers to make more resource available. For example, the system operator could contract with resource providers to make additional resources available at times, such as when there is a low residual situation, in return for a predefined contract payment.

8.13. These resources could take the form of:

(a) industrial demand side flexibility or small-scale aggregated flexibility not currently participating in the wholesale market

(b) payments to generation capacity to remain on standby when they would otherwise have remained out of market and

(c) payments to grid scale BESS to maintain a level of energy storage for potential low residual situations.

8.14. To attract resources, these payments would likely need to be higher than spot prices. Costs could be recovered by a levy across all wholesale purchasers or some similar approach.

8.15. As part of our 9 March 2023 decision paper, we decided not to progress the development of an option to procure additional resource outside of the spot market (referred to as 'Option K').

8.16. In our 22 November 2022 consultation paper, we noted the following potential drawbacks of out-of-market solutions:

(a) They could undermine spot market incentives for parties to commit resources. This arises because the mechanism allows resource providers to choose between making resources available solely via the spot market or keep them out of the spot market in the hope this will trigger the separate 'top-up' mechanism. Providers are likely to prefer the latter if given a choice because it would offer a higher reward (otherwise there is no increase above the normal level of resources).

(b) They could also undermine incentives for purchasers to enter into short-term contracts with resource providers (and therefore reduce the likelihood of contracts incentivising resource availability). This is because the additional resource procured via separate payment mechanism would lower expected spot prices. That will reduce the incentive on purchasers to self-insure via contracts.

(c) The issue with both effects is that they are self-reinforcing. Resource providers would typically reduce supply into the spot market, increasing the need for the (more generous) separate payment mechanism and so on. Likewise, the more resources that are contracted by the separate payment scheme, the less purchasers need to contract themselves. Ultimately this can affect investment as well as operational incentives.

(d) In addition, resources procured outside the spot market cannot be readily co-optimised with resources inside the spot market. Cost control may also be a challenge. Providers may view the system operator as an unduly motivated buyer. It would be difficult for the system operator to maintain negotiating tension unless it can walk away from negotiations or impose a price on sellers. Neither of these options would be straightforward to apply.

8.17. We consider that the reasoning noted in the previous consultation and decision papers still applies. We reviewed international schemes, and their experiences seem to support our earlier thinking. Out-of-market schemes, such as Australia's Reliability, Emergency Reserve Trader (RERT) scheme and the Electricity Reliability Council of Texas (ERCOT) Contingency Reserve Service (ECRS), have been expensive to operate and have not delivered on expected outcomes. Evidence from Texas shows that this approach does not guarantee the resources will be available and that withholding resource from the market will inflate spot prices with potentially little or no net improvement in reliability. See Appendix B for further details.

8.18. Furthermore, we have started to see evidence of purchasers entering into flexible-supply contracts with resource providers and other innovations in the demand-side space. Paying for warming contracts (or other generation to be on standby) would likely stifle this emerging innovation. Paying for thermal generation to be on standby can also be seen as paying for carbon and acting as a subsidy for unproductive or expensive plant.

8.19. Overall, our preliminary view is this option has significant risk of unintended consequences.

Box: Driving efficient solutions to promote consumer interests through winter 20223 - Analysis of submissions

Option K - additional resource outside of the spot market

While approximately half of submitters supported Option K, they also highlighted its substantial drawbacks. Of these, some supported it as a simple approach that could be implementable by winter 2023. Others saw it as a possible solution if other implementable options were not sufficient to address the issue. Others defined it as a potential long-term solution, which presented a high risk of unintended consequences.

Additional proposals

Submitters proposed nine additional options to help manage residual supply risk during winter 2023. The Authority decided not to implement any of these proposals.[52]

Among these, the CEO Forum (a working group of the CEOs of the six larger generators, four largest distributors and Transpower) proposed an out-of-market payment for resources that would be ring-fenced from other market mechanisms. This proposal was referenced across several submissions.

The Authority considered the CEO Forum's proposal to be an out-of-market solution – similar to Option K. This is because participants would receive payments outside the spot market through a non-integrated ancillary service. The Authority decided not to implement it for the same reasons it chose not to implement Option K. However, some of the submitters who did not support Option K due to its high risk of unintended consequences supported this proposal.

Q13: Do you agree with our preliminary assessment of the issues associated with procuring additional resource out of market? If not, what is your view and why?

Option 2: Out-of-market tender for emergency demand response

8.20. Despite the points made above, we have considered the idea of ring-fencing an out-of-market option to the demand-side. The theory is that there will be fewer incentives to game the market as the demand is already 'in' the market (ie, no arbitrage opportunities). This option would also have the potential benefits of:

(a) removing the distortionary effects of withholding generation resource

(b) accelerating the uptake of demand response.

8.21. This option would involve a tender for demand-response resources not currently offered into the market. To be successful, the resources would have to demonstrate an adequate level of availability over the winter peak periods and demonstrate the ability to respond to a signal to reduce demand.

8.22. The system operator could pay via out-of-market contracts for large industrial consumers (direct connects) to reduce demand for periods where there is less than 200MW of headroom in the supply stack. There are two options for implementing this scheme:

(a) The demand could be bid via the dispatchable demand product so that the system operator and other market participants have visibility of the load. This would also provide confidence that the participant will respond when required and the response can be measured.

Once the system operator forecasts a potential low residual situation with an agreed upon notice period the participant(s) would submit dispatchable

[52] The rationale behind this decision is detailed in the *Driving efficient solutions to promote consumer interests through Winter 2023 decision pape* available at: https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

demand bids to reflect their expected response. The bids would be priced greater than the $10,000/MWh scarcity price to ensure that the bids are not cleared in the market schedules unless required. Near real-time, the necessary response would be confirmed and the dispatchable bids would then need to be modified to reflect the certain nature of the reduction (ie, most likely, at $0.01/MWh).

(b) Alternatively, as large industrial consumers are already required to submit nominated bids to indicate their expected consumption, they could be required to modify their total nominated bid quantity to reflect the (paid-for) reduction in consumption.

8.23. Participation in the scheme would be ring-fenced to participants eligible to join the dispatchable demand regime. This is most likely large industrial users who do not currently have large incentives to vary their consumption (due to current contractual arrangements) or BESS when charging their batteries. Dispatch notification participants would not be able to participate in the scheme due to the lower dispatch-compliance requirements associated with dispatch notification.

8.24. This would be implemented as a temporary option. This would run for the next two to three winters until the operational coordination challenges have become manageable as additional resources become available to the market.

Potential benefits

8.25. A key benefit of this option is that it leverages existing market system functionality, and, therefore, could be implemented relatively quickly.

8.26. Although this option is temporary, it would provide participating large industrials with experience of participating in the wholesale market, offering a pathway to fully participate in dispatchable demand. The expectation is that this option would accelerate the uptake of dispatchable demand for large industrials.

8.27. This option is targeted at the demand side, so it does not create incentives to withhold generation resource.

8.28. Furthermore, it will provide the system operator with visibility of the load via Supervisory Control and Data Acquisition (SCADA) indications which assists with coordination.

Potential disadvantages

8.29. Large industrial users are significant electricity consumers and generally are better able to control their consumption. However, this control has to be planned and is usually worked around the primary production schedule of the industrial site. This means that the flexibility needed by the power system may not be available at the time it is needed due to production or safety constraints on the industrial site.

8.30. The truly flexible portion of a site’s load may already be offered into the instantaneous reserve market – providing a regular revenue stream with only the risk of a small number of disconnections per year. Over the last two years, a peak demand capacity product could have been called on 12 times per year – that is, each time a potential low-residual notice was issued by the system operator. This may represent an unacceptable interruption to plant operation for the industrial consumer.

8.31. As previously discussed in this paper, the Authority will conduct a survey of participant demand flexibility and the constraints associated with employing it.[53]

8.32. A further problem with this option is that it is still highly distortionary. Ideally, the demand would be bid at its value to the consumer. This would allow for efficient price signals and discovery.

8.33. However, because the participant is required to either reduce their bid price to $0.01/MWh (nominated dispatch bids) or reduce their total bid quantity (nominated non-dispatch bids) once called, it will distort price signals. The true value of the demand is not captured in the market price. In addition, the spot price will drop significantly once the demand reduction is called.

8.34. However, spot prices should be elevated to reflect the near scarcity situation of the power system. Lowering the spot price will not incentivise other participants to increase their offers (ie, it does not incentivise thermal generation to commit their resource).

8.35. It would likely reduce incentives for participants to invest in resource to manage their own risk exposure. In the long term, it will also undermine investment signals in new generation and flexible resources.

8.36. It is also likely that the system operator would come to rely on firm response in its security assessments. This could lead to industry resistance to any attempt to remove the scheme (and payments) at a later date.

8.37. It is very difficult to estimate the potential costs of such a scheme in the New Zealand context. Anecdotally, large industrial consumers have indicated that the current scarcity prices are too low to reflect the true value of their load. A 2018 Transpower study on the value of lost load (VoLL)[54] notes that VoLL results vary with points of supply with a high proportion of business consumers tending to have a higher VoLL. VoLL results generally vary between $17,000/MWh and $40,000/MWh and centre around $25,000/MWh.

8.38. If this is the case, we could expect activation prices in excess of $10,000/MWh. In addition to the activation costs, there may be an availability fee associated with any market tender. To provide 200MW of firm response, it is likely that any procurement would have to secure an excess of demand response to allow for production scheduling and plant availability.

8.39. Assuming the trigger for the use of the reserve product would be a system operator low-residual notice, there were 12 instances of a notice being issued each year in 2022 and 2023.[55] If each event lasted two hours, then the total capacity volume for the demand response for each year would be 4,800MWh, based on a requirement of 200MW for the full 2-hour period. If the tender price reflected the lower end of scarcity pricing at $10,000/MWh, this would be a total additional annual cost to consumers of at least $48 million.

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[53] You can access the survey at: https://info.ea.govt.nz/sl/1b9596.

[54] Transpower. *Value of lost load study.* November 2018. Available at: https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/publications/resources/Transpower%20VoLL%20Study%20June%202018%20-%20FINAL_0.pdf?VersionId=y5HYks4GD8YvXNu_jyRl8d6s7mba7ahf

[55] Until the end of August 2023

Out-of-market schemes in Australia and Texas

8.40. We have reviewed standby ancillary service schemes implemented by the Electricity Reliability Council of Texas (ERCOT) and the Australian Energy Market Commission (AEMC).

8.41. Their schemes were designed to address the standby ancillary service need through:

(a) Providing a participation path for resources that were otherwise excluded from the wholesale market while simultaneously providing a financial incentive to participate, or

(b) Providing a financial incentive for existing resources to withhold capacity when a potential shortfall situation is forecast.

8.42. ERCOT's out-of-market interventions to provide standby reserves have increased costs to consumers both directly (through the procurement of the services) and indirectly (through an increase in energy prices due to inducing artificial scarcity). Recent analysis from the Texan Independent Market Monitor shows that interventions likely raised the real-time market energy cost by around US$8 billion since the introduction of the service in June 2023.[56]

8.43. AEMC has also noted that 'interventions in or actions taken out of the market can be costly' (p. 64).[57] AEMC is currently consulting on introducing a service similar to New Zealand's dispatch notification product to bring price responsive resources into the market scheduling and dispatch process. This would, among other things, 'avoid the use of expensive out of market measures' such as their existing standby ancillary service (p.17).[58]

8.44. In summary, a key consideration when designing a paid standby ancillary service would be ensuring that the resources being procured are in addition to any resources that could otherwise have participated in the market.

8.45. If out-of-market payments are provided, there may be an incentive for participants to withhold resources from the wholesale market to induce the need for the standby ancillary service. This may then provide higher revenues for the participant than if they had provided their resource to wholesale market in the first place.

8.46. Further, any product that paid existing resources to provide a standby reserve would still rely on investment in new resources to provide any net increase in reliability. The transfer of capacity from the spot market to the standby ancillary service only increases the cost to consumers without increasing the net reliability of the power system. The peak capacity coordination issue is one of investment timing in generation and flexibility resources. Providing additional payments to existing participants is unlikely to speed up the consenting and construction of additional resources in the near term.

8.47. International attempts to provide payments for standby generation capacity out-of-market have resulted in no net benefit to system security. Unless a scheme is

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[56] ERCOT IMM. *IMM Concerns with the AS Methodology and Recommended Improvements.* September 2023, 22. Available at: [Agreement To Change Market Rules (ercot.com)]

[57] AEMC. *National electricity amendment (operating reserve market directions paper) rule.* August 2023, 3. Available at: https://www.aemc.gov.au/sites/default/files/2023-08/directions_paper_2023_0.pdf

[58] AEMC. *National electricity amendment (integrating price-responsive resources into the NEM) rule.* August 2023, 3. https://www.aemc.gov.au/sites/default/files/2023-08/ERC0352%20-%20Integrating%20price-responsive%20resources%20into%20the%20NEM%20-%20Consultation%20paper.pdf

carefully designed there is a high chance of the unintended outcomes highlighted above.

Summary of preliminary assessment

8.48. This option appears to come with significant drawbacks. The out-of-market nature of the product means that it is inefficient in the sense that it creates inefficient price signals, and in that resources cannot be readily co-optimised with other markets. The solution is not technology agnostic and is, therefore, not aligned with our objective to promote competition in the wholesale market. Furthermore, costs to consumers may be significant and difficult to control.

8.49. This option also relies on large industrials making the necessary changes to their processes and plant to be able to participate in the scheme in time for winter 2024. Willingness to participate, and the timelines to make these changes have yet to be tested with industry.

8.50. Overall, our preliminary assessment is this option has significant risks and that the benefits from potentially increased reliability to consumers are outweighed by the inefficiencies and potential costs. This is not a preferred option based on our preliminary assessment.

Q14: Do you think it would be beneficial to create an out-of-market tender for emergency demand response? If not, what is your view and why?

Option 3: Provide payments to participants to commit their resources to the market

8.51. To address some of the apparent disadvantages of out-of-market options, we investigated an option to incentivise providers to commit their resources to market. This would involve paying providers for the availability of residual or spare capacity.

8.52. The payment would be available for any uncleared energy or reserve offers, including any firming dispatchable demand that is not dispatched (for energy or interruptible load). As highlighted earlier, allowing dispatchable demand eligible resources to participate would open this mechanism to large scale BESS. The payment is not proposed to be available to dispatch notification products, as these are not firming products and have low dispatch compliance obligations. The system operator needs to be able to rely on the demand reduction if needed to maintain system security.

8.53. The option provides incentives for participants to commit their full capacity to the market. It may also accelerate the development of dispatchable demand and BESS investment by providing a mechanism for the provider to be paid for participating in the wholesale market.

8.54. The key challenge with this option would be determining an appropriate price for the residual. Because this is not a fully integrated option, it is difficult to know what price is efficient. Inefficient prices can lead to higher costs to consumers by limiting price discovery. Inefficient prices can also distort price signals for long-term investment.

8.55. Un-dispatched generation in the market is typically priced to reflect the value the generator places if it were required to use that resource now rather than at some future time. For example, if the hydro lake storage levels are low, a hydro generator might increase the price of some of its capacity that would use that storage to reflect the future value of that water and incentivise other generation to run in its place.

8.56. In effect, not generating with that water is the result that reflects the value of that water if there are other generators that can run at a lower price. This means that we should not use the generator offer price as a residual price to reflect the value of having that spare capacity. The generator has received the value for the resources they have been dispatched to use, and anything 'left over' is being reserved for future use and its value will be paid for when it is used.

8.57. If we used these 'reservation prices' to calculate the cost of providing an energy residual, the costs could be very high; un-dispatched offer prices of over $500/MWh are not uncommon.

8.58. As these prices can reflect the aim to either conserve a resource for future use or, in the case of thermal peakers, reflect the recovery of costs incurred when using a resource only occasionally, the offer price is higher than the cost of having the offer in place 'just in case'. This means that any price for the residual would need to be high enough to incentivise resource providers to make additional resource available (especially thermal plant), but low enough so as not to provide unnecessary costs to consumers.

8.59. As residual could be considered an extension of the current sustained instantaneous reserve (SIR)[59] product, linking the payment to the reserve price could be a simple way to determine the price. There would have to be a scaling factor applied to the payment, say 50%, to reduce the incentive to arbitrage reserve offers for availability payments.[60] Developing an appropriate scaling factor would need to carefully balance appropriate incentives to participate while managing costs to consumers.

8.60. The variations of this option include:

(a) paying for the 200MW residual (ie, the next 200MW in the merit order)

(b) paying for all available residual capacity

(c) paying for all available residual capacity – dispatchable demand only.

8.61. Variation (a) is intended to reduce the cost burden to consumers. That is, consumers only pay for what is needed to ensure the system operator can retain a 200MW residual. However, this may not provide strong enough incentives for generators to commit their resource as the offer stack changes throughout the day. It may be difficult for generators to determine whether they will be eligible for the availability fee ahead of real time. This variation does not address issues of uncertainty and therefore the willingness for generators to commit their resource.

8.62. Variation (b) is intended to remove the elements of uncertainty noted in variation (a). A payment would be made for all spare capacity. The availability payment would be available all year round (ie, it is not targeted at winter or other pre-defined periods). The key drawback of this option is that the potential cost to consumers is

[59] SIR replaces lost generation following the loss of a significant generator. SIR must act within 60 seconds of the loss and maintain its output for at least 15 minutes. The residual could be considered a replacement for a more gradual loss of supply – such as when a wind generator reduces output in response to a drop in wind speed.

[60] For example, to ensure that it does not create perverse incentives for providers to opt out of the SIR market.

uncapped and maybe considered excessive, especially during periods, such as summer, when historically there are large residuals.

8.63. Variation (c) is targeted at the demand-side only. The rationale is that generators should not be paid an availability fee, as this is an additional payment for costs that should already be recovered through their cleared offers. For generators, operating costs should be captured in their offers, an additional availability fee is not required for any capacity not used (ie, there is no fuel cost).

Potential benefits

8.64. The key benefit of this option is that it does not introduce significant price distortions. All information is available to market participants and the system operator in the bid and offer stack. It also does not elevate prices by removing generation or demand response from the bid and offer stack.

8.65. Variations (a) and (b) are technology agnostic and are, therefore, consistent with our objective of promoting competition through enabling a level playing field.

8.66. This option does not require significant changes to the core market system, so may be able to be implemented relatively quickly. However, it would require changes to the Clearing Manager's systems and potentially to the information provided to the Clearing Manager by the system operator.

8.67. This option may be effective in bringing forward some investment in demand flexibility services.

8.68. One of the potential barriers to participation raised by demand-side participants is the ongoing cost of maintaining and operating their load control and market bidding systems. Installing and maintaining the systems and processes necessary to control demand can be costly if they need to be retrofitted to existing process equipment.

8.69. An availability fee would provide a source of revenue to offset some operating and maintenance costs for participating demand-side participants. Only paying the fee when the demand response is bid but not dispatched ensures that no additional payment is received at the times that the participant is receiving the cost-reduction benefit of being dispatched.

Potential disadvantages

8.70. This option is not fully integrated or co-optimised, so we cannot know the true value of the residual and discover an efficient price. A 50% scaling factor applied to the relevant SIR price (or any other scaling factor) may over or under price the product.

8.71. The wholesale market process delivers efficient prices within the context of workable competition and the trade-offs between a resource either providing energy or an ancillary service.

8.72. Additional payments for generation or demand response distorts those prices and leads to consumers paying more for their energy than they would have otherwise if prices were efficient.

8.73. This is particularly true if an out-of-market payment makes a solution appear cheaper to the wholesale market than the cost of the next cheapest generation build or demand-response.

8.74. Signals to invest in more generation would be reduced leading to the more inefficient solution being used for longer. The cost of the inefficient solution would not be immediately apparent through wholesale prices but would be socialised across all consumers as a hidden cost on their retail bill.

8.75. In the case of variation (c), singling-out dispatchable demand is inconsistent with promoting competition. It does not provide a level playing field for different approaches and technologies to deliver generation or demand response.

8.76. We can estimate the potential costs to consumers for each of the variations of this option. The average North Island SIR price for the 12 months to 31 August 2023 was approximately $4.27/MWh, so this price along with a 50% scaling factor can be used for each estimate.

(a) If we assume that only the next 200MW of residual in the bid and offer stack will receive an availability fee, that will result in a direct annual cost of approximately $3.74 million to consumers.

(b) The average quantity of residual for the 12 months from September 2022 to August 2023 was approximately 1,908MW. Paying for this full residual would result in a direct annual cost of approximately $35.68 million to consumers. This cost is high and would be expected to grow as more generation and dispatchable demand is commissioned. However, the cost could be reduced if the availability fee is restricted to winter and shoulder periods.

(c) If we assumed that 200MW of demand response could be incentivised to bid at all times under this regime, that would result in a direct annual cost of approximately $3.74 million to consumers. However, this cost would grow as more dispatchable demand comes online.

8.77. All cost estimates above do not include the implementation and Code amendment costs.

8.78. As discussed earlier, it may be difficult to unwind the scheme because resource providers may argue that existing or new capacity cannot operate without the availability payment and the additional resilience provided by the scheme may be considered essential if investment in other technologies has not matched the wider system needs.

8.79. This option would likely require changes to the system operator's operational procedures.

Summary of preliminary assessment

8.80. While this option does not appear as distortionary as out-of-market solutions, it still comes with significant potential drawbacks. The option risks introducing inefficiencies and costs through over-procurement. Costs of ancillary services are shared, and the cost of overprovision are less obvious than the cost of administrative load control or occasional power cuts consistent with the reliability standard.

8.81. Overall, we consider this option risks undermining the current market design and that the benefits from potentially increased reliability to consumers is outweighed by the inefficiencies and potential costs. This is not a preferred option.

Q15: Do you think it would be beneficial to provide payments to resource providers for any uncleared generation and/or dispatchable demand? If not, what is your view and why?

Q16: What do you consider to be an appropriate scaling factor to determine the price for residual and why?

Demand response incentives in the UK, Singapore and Australia

8.82. We have reviewed schemes implemented by the United Kingdom, Singapore and Australia to incentivise demand response.

8.83. Singapore and Australia's schemes to incentivise demand response have had poor uptake. The schemes have been costly and not stimulated the expected level of response from consumers.

8.84. Singapore's experience shows the importance of getting the settings right. Revenue uncertainty, onerous requirements and harsh penalties can provide high barriers to entry and disincentivise participation.

8.85. The UK's experience has proved to be more successful. National Grid implemented a paid demand flexibility service (DFS) ahead of winter 2022/23. Electricity retailers could register as DFS providers to receive a guaranteed minimum payment of GBP3,000/MWh of response per event. It is then up to the retailers to decide how much of the payment to pass on to consumers.

8.86. This scheme saved over 3,300MWh of electricity during peak times and consumer feedback was positive. However, the payments to flexibility providers were also significant, GBP11.1 million.[61]

8.87. This cost could be justified based on expected severe shortfalls in supply, due to the impact of the Russian invasion of the Ukraine on European gas supplies. However, the scale of New Zealand's winter supply issues may not justify this cost.

8.88. Ultimately, consumers will likely bear the cost of any additional scheme. If a domestic consumer incentive scheme is implemented, it is likely that those consumers most able to reduce demand without impacting their lifestyle will be wealthier consumers with more discretionary electricity consumption. This means that, once any compensation payments to flexible consumers are considered, consumers without flexibility will likely disproportionately bear the burden of paying for the standby ancillary service.

8.89. We consider that, if industry members reduce their wholesale market risk by using consumer resources, consumers should also accrue benefits. For example, the uptake of consumption shifting plans (free hour of power, three hours of free power etc.) allows consumers to make a consumption habit change in response to clear and meaningful signals. Similarly, suppliers of solar and battery systems are able to offer discounted retail tariffs in return for the ability to manage the consumer's peak demand.

8.90. Overseas evidence suggests infrequent, event-driven, rewards[62] (ie, one-off rewards for changing consumption in response to a system event) do not yield a strong response except in the most extreme circumstances (Appendix B). This may

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[61] ESO. *Demand flexibility service. Winter 2022/23 review.* August 2023. Available at: https://www.nationalgrideso.com/document/287006/download

[62] Gyamfi, S., Krumdieck, S.; Urmee, T. *Residential peak electricity demand response: Highlights of some behavioural issues.* Renewable and Sustainable Energy Reviews, Vol.25, pp.71-77. 2013. DOI: https://doi.org/10.1016/j.rser.2013.04.006

be due to the reluctance of consumers to change their habits at short notice, increasing inconvenience and the perceived cost. Whereas the ‘free-power’ retail tariffs discussed allow consumers to change their routines on a habitual basis, making it easier to make the change to their consumption timing. Though it should be noted, not all consumers respond to the same incentives or signals, making the design of a ‘one-size-fits-all’ scheme impossible.

Preliminary assessment of interim options

8.91. Based on the lessons learned during winter 2023, on our assessment of the challenges for winter 2024 and 2025 (see Appendix A), and our analysis of international experiences (see Appendix B), we believe that an interim option may not be required.

8.92. As previously noted, no power system can achieve 100% reliability, and our market settings also reflect this. New Zealand’s market settings are designed to allow for scarcity prices to emerge when appropriate, as this incentivises investment and innovation in the long term.

8.93. The reliability standard when calculating settings, such as the winter capacity margin, assumes that the cost of the expected hours of shortfall (either energy or reserve) per year equates to the cost of investment in peaking generation to mitigate that shortfall. A reduction in the assumed hours of shortfall, and related changes to the system security settings, would be expected to cost consumers more than if the next cheapest peaking resource were built instead.

8.94. Solutions that provide out-of-market payments can subsidise responses that, in reality, cost more than the next best option for building generation. This can artificially extend the time that the interim solution is needed and further increase the additional cost to consumers.

8.95. In the short term, any interim option is likely to be distortionary (out-of-market solutions), inefficient (all options presented) and add costs to consumers (all options). They are effectively costly insurance products that shift the risk from industry participants to consumers.

8.96. It would also be an insurance policy that consumers would have little choice in accepting and no ability to forgo for other options on an individual basis. A more efficient, and potentially lower cost solution would be to ensure that the resources that are currently available in the wholesale market are providing the right price signals early enough to maintain security of supply.

8.97. These price signals must also provide a clear and reliable longer-term signal for the need for investment, leading to the development of a power system that can operate effectively and efficiently in a highly renewable future.

8.98. We consider that the Authority’s resources and time would be best spent on investigating Code amendments to further remove barriers to entry for demand-response and batteries and to accelerate their participation in the wholesale market.

Q17: What is your view on the factors the Authority should consider when valuing the costs associated with a standby ancillary service?

Q18: What other options should be considered to better manage residual supply risk for winter 2024?

Q19: Do you have information on any other international standby ancillary services and their positive impacts? If yes, please share your information

Appendix A: Lessons from winter 2023 and the preliminary outlook for winter 2024 and winter 2025

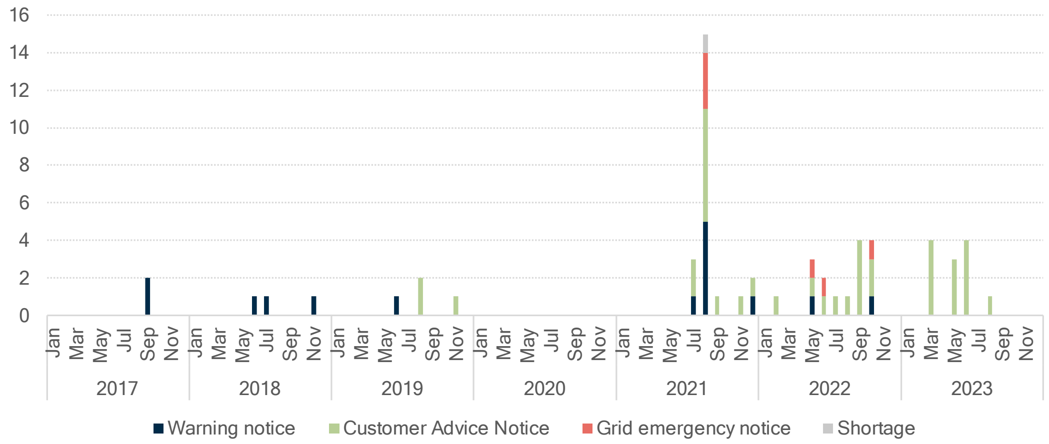
1. The following assessment of winter 2023 and the outlook for winter 2024 and winter 2025 have been used to inform this paper.

Winter 2023 passed with no loss of supply incidents due to peak coordination issues

2. During winter 2023, consumers did not experience forced outages due to coordination issues despite a number of significant plant failures and high peak demand periods. The Authority will be releasing an analysis of the notified low residual periods and the industry response later in 2023.

3. The system operator issued 12 Customer Advice Notices (CANs) to advise of a low-residual situation[63] between March and August 2023 (Figure 1).

Figure 1: Number of low residual and insufficient generation notices by month, January 2017 to August 2023.



4. A 'low-residual situation' is when the projected headroom in the supply stack (after taking into account energy, reserve and frequency keeping requirements) is less than 200MW. Once residuals are below 200MW, there is little room to manage any large unforeseen changes in generation or demand whilst maintaining standard reserve levels.

5. If there is insufficient generation to cover demand, the system operator can release Warning Notices (WRNs), or Grid Emergency Notices (GENs). Notably, the system operator did not issue any WRNs or GENs this winter. Participants responded to the CANs, and demand control was not required.

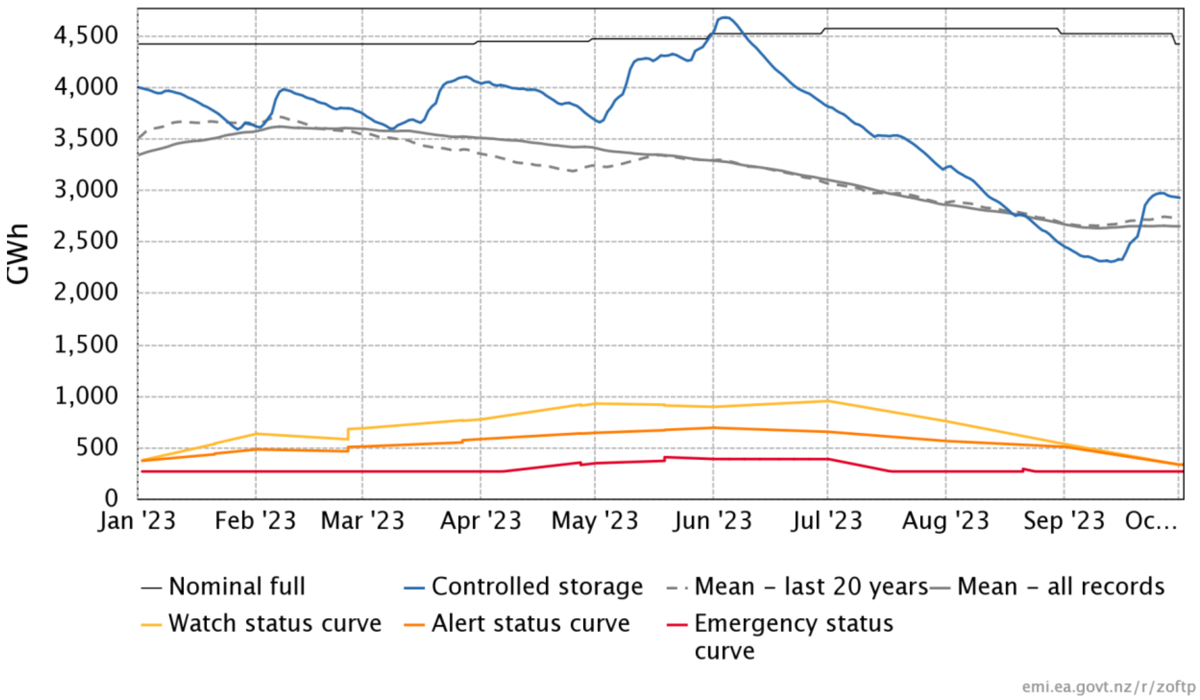
[63] Low Residual Situation CANs were introduced in May 2019. See: Transpower. *Costumer Advice Notice.* May 3, 2019. Available at: CAN Industry Update Introduction of Low Residual Situation 3098623458.pdf (amazonaws.com)

High hydro storage increased the challenge of meeting peak demand

6. For the past three years, New Zealand has experienced La Niña weather patterns. This contributed to dry weather in the South Island, and wet conditions across the upper half of the North Island.

7. Overall, hydro storage has been high for the first half of the year as illustrated by Figure 2 below.

Figure 2: Historical electricity risk curves (ERCs) against controlled storage



8. Although high hydro storage assists with meeting New Zealand's energy needs over winter, high hydrology can increase the challenge of meeting peak demand. This is because – when hydro storage and generation is high – the average electricity price tends to be lower. Lower prices reduce the commercial incentives for thermal generators to offer into the market. Consequently, there is less spare capacity on the system to maintain supply when there are unexpected changes (eg, such as a sudden increase in demand or a sudden drop in wind generation).

9. Low thermal-unit commitment and below-average wind generation led to the system operator issuing seven low residual CANs between May and June,[64] even though demand was not exceptionally high.

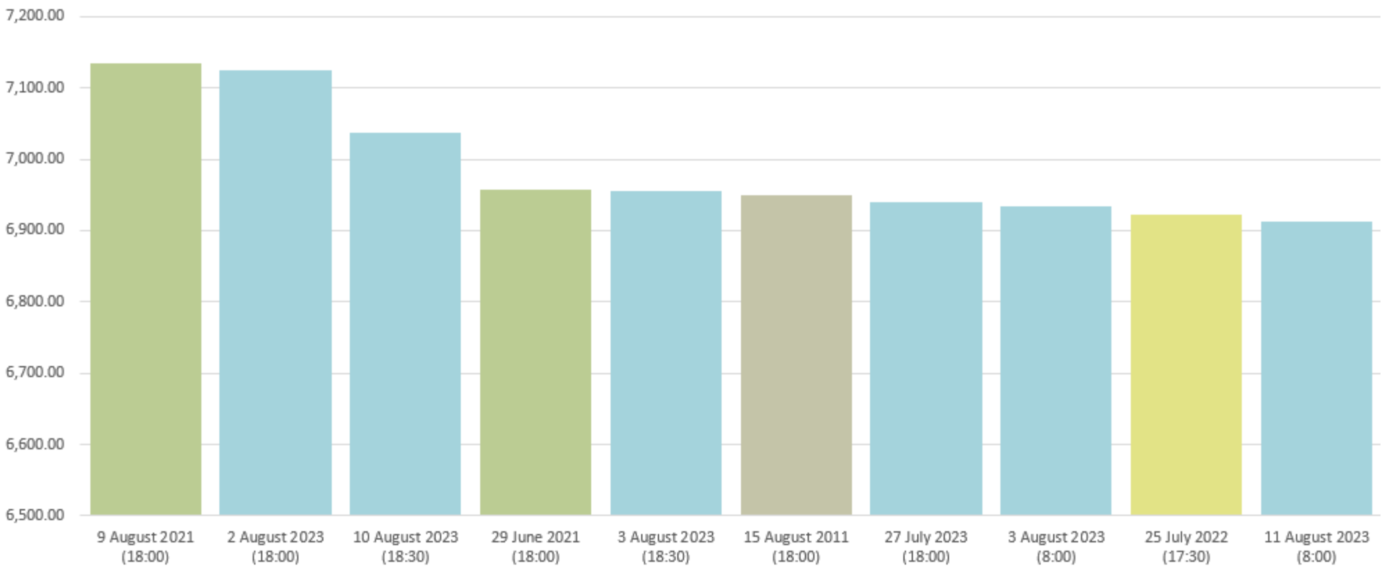
10. The situation started to reverse in June with hydro storage declining sharply. Higher prices along with the unplanned outage of Huntly unit 5 at the end of June resulted in greater thermal commitment over the remainder of winter.

[64] The system operator also issued 4 low residual CANs in March. These CANs coincided with an HVDC outage.

The system experienced six record demand peaks this winter

11. Average temperatures for August were the coldest experienced in seven years.[65] Six of the top 10 record demand peaks occurred this winter, with five of these occurring in August (Figure 3). Despite these high peaks, high thermal commitment meant that the system operator only issued one low residual situation CAN for the 11 August 2023 morning peak. All other demand peaks passed with residuals of between 322MW and 547MW. There were no periods of insufficient generation, and the system operator did not have to instruct any participants to reduce discretionary demand.

Figure 3: Top MW demand peaks (trading period average)



High thermal fuel availability provided resilience against asset failures

12. A significant amount of generation capacity was on unplanned outage this winter. Most notable was the tripping of Huntly unit 5 on 30 June 2023 followed by an extended outage.[66] This removed 403MW of capacity from the system. Genesis responded by committing its three Rankine units.

13. The three-month planned outage by Methanex during winter meant that approximately 90TJ of gas was available to other users, such as the Rankine units, allowing for thermal plant to run relatively unconstrained. It is also worth noting that while extra gas was available, the coal stockpile was also high heading into winter and sufficient to run a single Rankine unit at full capacity for a 12-month period.[67]

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[65] NIWA. *Climate Summary for August 2023.* September 2023, 4. Available at: https://niwa.co.nz/climate/monthly/climate-summary-for-august-2023

[66] Huntly unit 5 is expected to return to service in late January 2024.

[67] Transpower. *Winter 2023 review.* October 2023. Available at: https://static.transpower.co.nz/public/bulk-upload/documents/Transpower%20Winter%202023%20Review.pdf?VersionId=IxfXgTAuXrk7rjbDNoyy_YFg.bWND481

14. Additionally, the Stratford peaker GT22 (thermal), Manapouri (hydro) and Kawerau (geothermal) plants experienced unplanned outages. While the units at Manapouri and Kawerau have returned to service, Contact Energy has advised its Stratford peaker GT22 will not be returned to service until February or March 2025. The Ahuroa gas storage facility also downgraded its storage capability.

15. These unplanned outages highlight that some of Aotearoa New Zealand's generation fleet is ageing, impacting its reliability. This increases the risk of meeting the system's energy and capacity needs in winter 2024 and beyond.

16. High thermal commitment over July and August resulted in fewer low-residual situations and enabled continued supply during periods of high peak demand. However, the reduction in capacity meant that the power system was vulnerable to any further asset failure, or a severe cold weather event.

The industry has worked together to meet the challenges of winter 2023

17. The pan-industry grid emergency exercises in May 2023 provided an opportunity for the system operator and participants to practise and refine their operational and communication processes during potential tight supply situations.

18. In its review of winter 2023, the system operator has noted that this year more planned outages were scheduled to avoid peak demand periods than previous years.[68] This increased capacity and flexibility to meet peak demand periods.

19. The system operator also noted that market participants responded to low residual situation CANs by committing more generation and cancelling outages: 'the response from participants avoided four potential grid emergencies, which would have either seen the power system operating with less reserve than required or managing controllable load down' (p. 20).[69]

20. Anecdotal evidence from engagement with industry stakeholders suggests that the options implemented for winter 2023 have been helpful with managing the risks for winter 2023. Improved information around the residual, wind generation, price sensitivities and the level of available discretionary demand along with cooperation by industry and improved communications from the system operator have resulted in good outcomes for this winter.

21. Following the five low residual CANs published between June and August, distributors indicated that an average of 167MW was available as discretionary demand.

We expect the coordination challenges for winter 2024 and 2025 to be similar to this winter

22. The system operator has previously expressed concerns about the outlook for winter 2024. Referring to its Security of Supply Assessment published in June 2022,

[68] Transpower. *Winter 2023 review.* October 2023. Available at: https://static.transpower.co.nz/public/bulk-upload/documents/Transpower%20Winter%202023%20Review.pdf?VersionId=IxfXgTAuXrk7rjbDNoyy_YFg.bWND481

[69] *Ibidem*

[70] the system operator suggested that that under certain scenarios the winter capacity margin could fall under the security standard in the Code as early as 2024.

23. In December 2023, the system operator will publish a detailed analysis of the peak and energy demand challenges that they foresee for winter 2024 and beyond. However, in their review of winter 2023, the system operator notes that ‘the sustained growth in demand and intermittent generation informs our view that the challenges in winter 2024 will be similar to this winter and demonstrates the need for investment in flexible resources to balance demand’ (p. 6).[71]

24. The following sections outline the differences we expect to see between this winter and the next two winters.

El Niño conditions may or may not increase coordination challenges

25. The National Institute of Water and Atmospheric Research (NIWA) confirmed the change to El Niño conditions was declared at the end of September 2023. El Niño brings stronger or more frequent winds from the west in the summer, which can lead to wet conditions in the west and drier conditions in east of the country. El Niño winters tend to bring more southerly winds which bring colder weather.

26. NIWA is predicting normal to above normal rainfall over summer in the west and south of New Zealand, where some hydro catchments are located.

27. It is too early to predict the likely impact on hydro storage. As at the end of October, national storage is currently slightly above average for this time of year.[72] The expected rainfall over summer could reduce the likelihood of an energy shortage during 2024. However, as discussed earlier, high amounts of hydro generation could also reduce the amount of slow start thermal generation available to start up quickly.

28. If hydro storage gets low, hydro generators will start conserving water instead of generating. This will be signalled through an increase in the offer price for generating with stored water resulting in an increase in average wholesale prices. Slow start generators, such as Huntly units 1, 2 and 4 and the Stratford combined cycle unit, would be more likely to run and may reduce the likelihood of peak capacity coordination issues.

Increased investment is starting to impact installed capacity

29. The capacity of installed resource is expected to change over the near term. New generation is due to be commissioned, battery energy storage systems are planned or under construction and efficiency improvements to existing hydro generators are

[70] Transpower. *Security of Supply Assessment 2023.* June 2023, 26. Available at: https://www.transpower.co.nz/system-operator/planning-future/security-supply-annual-assessment

[71] Transpower. *Winter 2023 review.* October 2023. Available at: https://static.transpower.co.nz/public/uncontrolled_docs/Winter%202023%20Review.pdf?VersionId=Zxdbk14diwGA43UuzjYGV8IhGj44cbji

[72] EMI. *Historical electricity risk curve.* Available at: https://www.emi.ea.govt.nz/Environment/Reports/3UN1KD?_si=v%7C3

being made. This increase is against a backdrop of expected thermal generation retirement.

30. New intermittent generation sources will help with energy security of supply, but they do not contribute equally to addressing capacity concerns. The winter capacity margin calculation performed by the system operator typically only includes 20% of the installed capacity of intermittent generation. It should be noted that total wind generation can reduce to almost zero during particularly still periods.

31. New sources of firming capacity such as hydro, geothermal and Battery Energy Storage Systems (BESS) will contribute to alleviating capacity concerns (Table 5). Emerging demand-response solutions are also an important area of flexibility to assist with managing demand peaks.

Table 5: An overview of the announced investment in firming generation (including BESS) for winter 2024 and winter 2025

For winter 2024			For winter 2025		
Plant	Type	MW	Plant	Type	MW
Tuai and Karapiro	Hydro (upgrades)	23	Tuai	Hydro (upgrade)	6
Rotohiko	BESS	35	Tauhara	Geothermal	174
			Te Huka	Geothermal	51
			Ruakākā	BESS	100
Total		58	**Total**		331
Large known outages or retirements (firming generation)					
Stratford peaker GT22	Gas	-100	TCC	Gas	-360

32. Genesis has also completed engineering reviews for large grid-scale batteries at Huntly.[73] Its scale and timeframe, however, have yet to be announced.

33. A recent Transpower report[74] has highlighted the growing investment in BESS. Transpower advises that it 'currently has 410MW of dedicated BESS in its connection queue, and a further 3,035MW of solar with BESS firming (330MW of which is consented and 230MW of this is currently in delivery). An additional

[73] Genesis. *FY23 Results presentation.* August 2023, 24. Available at: https://media.genesisenergy.co.nz/genesis/investor/2023/genesis_fy23_results_presentation.pdf

[74] Transpower. *Whakamana i Te Mauri Hiko.* October 2023. Available at: https://static.transpower.co.nz/public/uncontrolled_docs/Monitoring%20Report%20-%20October%202023%20-%20Final.pdf?VersionId=EsTmICODtCwlKdlj97z.R83sqdbET7jN

500MW is now under investigation and expected to be completed within 12 months' (p. 14).

Summary of challenges for winter 2024 and winter 2025

34. We expect the challenges for winter 2024 to be similar to the challenges experienced this winter.

35. Underlying demand growth has remained flat due to a decrease in industrial load, although there is strong evidence of growing demand peaks.

36. Although the Stratford peaker GT22 is expected to be unavailable for winter 2024, Contact has recently announced that it has sufficient gas contracted and available operating hours to operate its Taranaki Combined Cycle Power Station (TCC) across winter 2024.[75]

37. Huntly unit 5 is expected to return to service in late January 2024.

38. While Genesis will no longer be able to rely on its arrangement for supplying gas to Methanex in the summer in exchange for gas in the winter, Genesis expects its new well in the Kupe gas operation (KS-9) to provide additional gas in early 2024.[76]

39. Overall, the availability of thermal generation for winter 2024 (including sufficient gas and coal storage), combined with the expected commissioning of an additional 58MW of firming generation and the expected availability of (an average of) 167MW of discretionary demand indicate that residuals may continue to be tight but manageable for winter 2024.

40. Winter 2025 may be more challenging due to the planned retirement of TCC. However, an additional 225MW of geothermal generation is expected to be commissioned by winter 2025 and there is evidence of significant quantities of BESS in the investment pipeline.

41. This analysis highlights the importance of accelerating the uptake of demand response and BESS solutions for winter 2024 and winter 2025.

[75] Energy News. *Contact shelves TCC overhaul.* May 2023,19. Available at: Contact shelves TCC overhaul | Energy News

[76] Genesis. *Constant change.* 2023. Available at: https://media.genesisenergy.co.nz/genesis/investor/2023/genesis_fy23_integrated_report.pdf?_ga=2.154961723.2042881402.1696287647-1858662414.1696287647

Appendix B: Review of international experience

1. We have looked at other jurisdictions to inform our options for a potential standby ancillary service and options to incentivise demand response.

ERCOT (Electricity Reliability Council of Texas) contingency and emergency event services

2. ERCOT's out-of-market interventions to provide standby reserves have increased costs to consumers both directly (through the procurement of the services) and indirectly (through an increase in energy prices due to inducing artificial scarcity).

3. Since 2007, ERCOT has procured the Emergency Response Service (ERS) to decrease the likelihood of system-wide load shedding. This out-of-market service is open to both qualified loads and generators and is procured four times a year. Participants are required to provide an agreed-upon quantity of megawatts within 10 to 30 minutes to help prevent or alleviate an actual or anticipated Energy Emergency Alert (EEA) event.

4. During Winter Storm Uri in February 2021, the majority of the ERS fleet was deployed and exhausted within 12 hours of deployment. The overall ERS fleet generally met or exceeded the aggregate obligation for the duration of the event, although ERS loads generally over-performed while ERS generators generally under-performed.[77]

5. After the event, two key changes were implemented. Firstly, ERCOT can deploy ERS sooner rather than holding back service until the organisation has called an EEA when Physical Responsive Capability falls below 3,000MW and is not expected to rise above that threshold within 30 minutes. This scenario occurred on July 13, 2022, and ERCOT deployed as much as 1,011MW of ERS for approximately 3.25 hours.[78]

6. Secondly, the ERS budget was increased from US$50 million to US$75 million in 2022 to allow ERCOT the flexibility to procure ERS for longer-duration events with a contract term from individual ERS resources to better address seasonal needs and make other administrative changes to the programme.[79]

7. The ERCOT Contingency Reserve Service (ECRS) was introduced in June 2023 to support grid reliability and mitigate real-time operational issues to keep supply and demand balanced. It was intended to provide additional insurance against the significant blackouts suffered in the Texas electricity system during Winter Storm Uri.

8. However, the ECRS procurement and deployment criteria have reduced supply and significantly raised demand for the ancillary service. At times of potential shortage,

[77] Potomac Economics. *2021 State of the market report for the ERCOT electricity markets.* May 2022. Available at: https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf

[78] Potomac Economics. *2022 State of the market report for the ERCOT electricity markets.* May 2023. Available at: https://www.potomaceconomics.com/wp-content/uploads/2023/05/2022-State-of-the-Market-Report_Final_060623.pdf

[79] The fund has been US$50 million since 2012 and its average price was lower than the average price paid for both responsive reserves and non-spinning reserves in 2021 (before the price increase).

generators are paid to withhold a proportion of their capacity from the wholesale market, and flexibility resources (demand response) are paid to reduce consumption. The scheme is designed to allow up to 50% of the procured reserve to be supplied via demand response.

9. This happened on 20 June 2023, when ECRS was first used and resulted in the market schedules reflecting a shortfall of generation. This shortfall was due to the ECRS capacity being removed from the market. Consequently, wholesale prices leapt to their price ceiling of US$5000/MWh while generators also received significant payments for the volume that they had withheld and were not generating with.

10. Recent analysis from the Texan Independent Market Monitor shows that the ECRS likely raised the real-time market energy cost by around US$8 billion since its introduction in June 2023. Additional costs continue to accumulate, notably in early September.[80]

Australian Energy Market Commission (AEMC) standby reserve products and demand side participation schemes

11. Recent additions to the Australian National Electricity Market (NEM) demonstrate the high costs associated with out-of-market schemes and the limited impact on participation of paid demand response schemes. In recent consultation, the AEMC has decided to focus on incremental improvements to develop and publish more information to the market and to focus on a proposal to facilitate the uptake of demand response.

Standby Reserves

12. The Australian Energy Market Operator (AEMO) may intervene with directions, instructions, and/or Reliability, Emergency Reserve Trader (RERT) contracts to procure emergency reserve when a shortfall in supply or reserves is forecast.

13. Directions are issued to registered participants (generators and scheduled loads) to operate at a specified output or consumption level and are dispatched through normal market processes. Generators are compensated for responding to the direction.

14. Instructions are sent to Network Service Providers (NSPs) to load-shed customers to maintain the integrity of the power system. These customers are then compensated.

15. Under the RERT framework, AEMO secures contracts for emergency out-of-market reserves from providers, which can be activated (or pre-activated) upon request. These providers are grouped into short-notice, medium-notice, and long-notice providers.

[80] ERCOT IMM. *IMM Concerns with the AS Methodology and Recommended Improvements.* September 2023, 22. Available at: Agreement To Change Market Rules (ercot.com)

16. The AEMC states that 'interventions in or actions taken out of the market can be costly' (p. 64).[81] The RERT has only been activated a handful of times since 2021 but the cost per MWh has increased markedly from AU$10,676.02 per MWh in May 2021[82], to AU$ 50,334.32 per MWh in 2023[83]. The total cost associated with the RERT was AU$0.66 million in 2020/21, AU$130.6 million in 2021/22, AU$2.06 million in 2022/23. These costs include the cost of compensating providers for their availability, pre-activation, activation and intervention costs. Consumers bear the full cost of this service through retailer charging.

Market integrated standby ancillary service

17. In 2020, AEMC consulted on the introduction of an operating reserve market[84] to help respond to unexpected changes in supply and demand. In August 2023 the AEMC proposed not to progress this option[85] because it would not offer any performance improvements relative to the current arrangements while introducing additional costs for the market. A final decision on this proposal is expected on 21 December 2023.

18. AEMC modelling shows that 'a fleet that evolves to firm renewables with very flexible storage technologies:

    a. will likely be well-placed to manage net demand uncertainty in operational timeframes (five minutes to an hour) so long as participants have sufficient storage to account for such uncertainties

    b. should be reasonably well-placed to manage net demand needs over the course of a full day, so long as sufficient depth of charge and other resources are available to manage the potential for longer duration events to occur.'[86]

19. The AEMC is instead seeking stakeholder input on two additional incremental improvements:

    a. develop and publish more information to the market and

    b. procure frequency control ancillary services at a regional level.

20. These improvements provide the opportunity to observe the future fleet's response to changes in market signals, before introducing any complex changes.

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[81] AEMC. *National electricity amendment (operating reserve market directions paper) rule.* August 2023, 3. Available at: https://www.aemc.gov.au/sites/default/files/2023-08/directions_paper_2023_0.pdf

[82] AEMO. *Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q2 2021.* August 2021. Available at: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2021/rert-quarterly-report-q2-2021.pdf?la=en

[83] AEMO. *Reliability and Emergency Reserve Trader (RERT) End of Financial Year 2022-23 Report*. August 2023. Available at: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2023/rert-end-of-financial-year-report-2022-23.pdf?la=en

[84] AEMO defines 'operating reserves' as the capability to respond to large continuing changes in energy requirements, with minimum levels required for the system operator to maintain system security and reliability. Such reserves are currently provided 'in-market' informed by the collective decisions of many participants in aggregate. These are not explicitly priced, but implicitly.

[85] AEMC. *Enhancing reserve information (formerly Operating reserves)*. June 2023. Available at: https://www.aemc.gov.au/rule-changes/enhancing-reserve-information-formerly-operating-reserves

[86] AEMC. *National Electricity Amendment (Operating Reserve Market Directions Paper) Rule*. August 2023. Available at: https://www.aemc.gov.au/sites/default/files/2023-08/directions_paper_2023_0.pdf

Demand response initiatives

21. In 2021, AEMO introduced Wholesale Demand Response (WDR). This mechanism provides a payment to demand side participants for responding to a dispatch instruction.[87]

22. The WDR provider receives a payment for the quantity of load they have curtailed relative to a baseline consumption calculated by AEMO at the cleared wholesale price. These payments are charged to the retailer. The WDR provider must also pay a compensation payment to the retailers of the load they have reduced at a regulated tariff rate.

23. To date, only one participant has registered for the WDR, providing up to 65.3MW of demand response at any given time. This compares to a NEM winter 2022 demand peak of 32,553MW.[88]

24. Additionally, in August 2023, AEMC opened consultation on integrating price responsive resources into the electricity market.[89] The proposal would implement a scheme much like the dispatch notification scheme recently implemented in New Zealand.

UK demand flexibility service (DFS)

25. Following the impact of the Russian invasion of Ukraine on European gas supplies, the National Grid electricity system operator (ESO) forecast significant issues meeting winter peak demand in 2022/23. In response, National Grid implemented a paid demand flexibility service (DFS).

26. The service ran from November 2022 to March 2023, with 20 test events and two live events taking place. DFS will continue as an enhanced action for winter 2023/24. This will allow ESO to deliver both test events and, where necessary, live events.

27. Electricity retailers can register as DFS providers to receive a guaranteed minimum payment of GBP3,000/MWh of response per event. It is then up to the retailers to decide how much of the payment to pass on to consumers.

28. Half the tests that ESO will run in 2023/24 will use the guaranteed GBP3,000/MWh payment. The second half will become competitive, subject to the total volumes participating in the service.[90]

29. The response quantity is assessed against a baseline consumption estimate. This baseline is calculated using an average consumption of a number of working or non-working days over the preceding 60 days. The system operator issues a notice to participants that a response is required, and participants signal to their customers to reduce their demand.

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[87] AEMO. *Wholesale Demand Response: High-level Design*. June 2020. Available at: https://www.aemo.com.au/-/media/files/initiatives/submissions/2020/wdrm/wdrm-high-level-design-june-2020.pdf

[88] Australian Energy Regulator. *Seasonal peak demand – NEM.* Available at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/seasonal-peak-demand-nem

[89] AEMC. *National electricity amendment (integrating price-responsive resources into the NEM) rule.* August 2023, 3. Available at: https://www.aemc.gov.au/sites/default/files/2023-08/ERC0352%20-%20Integrating%20price-responsive%20resources%20into%20the%20NEM%20-%20Consultation%20paper.pdf

[90] ESO. *Demand Flexibility Service (DFS).* Available at: https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility-service-dfs

30. While the DFS provided incentive for an urgent and significant response to an unforeseen supply event, New Zealand is not currently facing a supply shortfall or comparable scale or immediacy. The cost of implementing any solution should be lower than the next cheapest generation investment.

31. Ofgem, the energy regulator for Great Britain, is also seeking input on how to best attract domestic energy users to becoming flexible energy consumers able to reap the benefits of a net zero energy system.

32. This scheme was successful and saved over 3,300MWh of electricity during peak times and consumer feedback was positive. The payments to flexibility providers were significant, GBP11.1 million.[91] This could be justified based on expected severe shortfalls in supply, however, the scale of New Zealand's winter supply issues may not justify this cost.

Singapore demand side management sandbox

33. Singapore's experiment with demand response and interruptible load shows the importance of getting the settings right. Revenue uncertainty, onerous requirements and harsh penalties can provide high barriers to entry and disincentivise participation.

34. In October 2022, the Energy Market Authority (EMA) announced a new regulatory sandbox to support participation in demand response programmes by streamlining procedures, reducing penalties and providing clearer activation timeframes. The temporary sandbox scheme was launched on 1 January 2023 and will run until 31 December 2024. It comprises two existing programmes: Demand Response Programme and Interruptible Load Programme.

35. The Demand Response (DR) programme was introduced in 2016 to enable eligible business consumers to participate directly in the wholesale market. Under the programme, they can cut their electricity demand voluntarily when wholesale electricity prices are high or when system reliability is low. In exchange, they receive a share in the system-wide benefits.

36. DR providers receive one-third of the savings arising from the reduction in electricity prices as incentive payments. This ensures that most of the benefits are accrued to the broader consumer base, while providing a fair return to DR participants. The incentive payment will be up to S$4,500/MWh, which is the existing ceiling for wholesale electricity prices.[92]

37. In 2020, the EMA consulted on the DR programme to encourage its uptake.[93] In their consultation they note that 'participation in the DR programme had been low since its inception, with only 4 instances of dispatch in total (2 dispatches in 2018, 2 dispatches in 2020). Energy DR capacity registered was also only 0.05% of peak load' (p. 4).

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[91] ESO. *Demand Flexibility Service Winter 2022/23 review.* August 2023. Available at: https://www.nationalgrideso.com/document/287006/download

[92] Energy Market Authority. *Factsheet demand response interruptible load.* Available at: https://www.ema.gov.sg/content/dam/corporate/our-energy-story/energy-demand/factsheet-demand-response-interruptible-load_20221103.pdf

[93] Energy Market Authority. *Review of the demand response programme in the national electricity market of Singapore consultation paper*. Available at: https://www.ema.gov.sg/partnerships/consultations/2020/review-of-the-demand-response-programme-in-the-national-electricity-market-of-singapore

38. At the launch of the sandbox there were three DR providers and four DR facilities in the market. In July the registered capacity of DR facilities increased by around 37%. However, there do not appear to be any new providers participating.

39. Participants in the Interruptible Load (IL) Programme are paid to be on standby to reduce their committed electrical load during conditions of tight power generation supply. Consumers can offer to reduce their electricity consumption through their electricity retailer or a Demand Response Aggregator. This programme was established in 2004 to improve the power system stability during times of supply disruptions.

40. As at 31 December 2022, there was no registered capacity for IL for primary reserve. In 2022, however, there was a slight increase in capacity and frequency use of IL registered capacity for contingency reserves. It appears that no new participants have joined the IL programme since the sandbox trial was established.

41. During the sandbox trial, participants continue to be subjected to the existing compliance thresholds and penalty amounts. If the participant assesses that it should not have been penalised or the penalty amount should have been lower under the sandbox scheme, it can submit the penalty refunds request to the EMA and Energy Market Company. From January to July 2023, they have given back around S$194,000.[94]

[94] Energy Market Company. *Demand side management sandbox.* Available at: https://www.home.emcsg.com/about-emc/media-news-annoucements/media-news/Demand-Side-Management-Sandbox#:~:text=The%20DSM%20Sandbox%20enhances%20the,when%20there%20is%20tight%20supply.

Appendix C: Format for submissions

Submitter	
Questions	Comments
Q1: Do you agree with the principle that the winter capacity margin should be based on the trade-off between the cost of the hours of reserve or energy shortfall and the cost of the peaking generation needed to mitigate it? Do you have any other suggestions on factors the Authority should consider and why?	
Q2: Do you agree with our assessment of the incentives for demand response? If not, what is your view? Are there other criteria that the Authority should consider?	
Q3: Other than financial incentives, what are the other barriers to entry for demand response participation in the wholesale market that you have identified?	
Q4: Do you agree that the Authority should focus its resources on identifying and lowering barriers for BESS and demand side flexibility to participate in the wholesale and ancillary services markets? If so, where do you think the	

Authority should focus first?	
Q5: Do you agree that any solutions should satisfy these principles? If not, what is your view and why? Are there other principles that the Authority should consider?	
Q6: Do you agree that a standard product for financial ‘super peak’ hedges is required?	
Q7: What factors do you think we should consider in the design of such a product?	
Q8: Do you agree with our assessment of the risk for the medium to long term?	
Q9: Do you think it would be beneficial to create a new integrated standby ancillary service? What is your view and why?	
Q10: How should the costs for a standby ancillary service be allocated?	
Q11: How should the residual requirement be set? Should it be an operational setting or dynamically calculated? If it is dynamically calculated, what factors	

should be considered in the calculation?	
Q12: How should deficit (scarcity) standby residual be priced in relation to scarcity energy and scarcity reserve prices?	
Q13: Do you agree with our assessment of the issues associated with procuring additional resource out of market? If not, what is your view and why?	
Q14: Do you think it would be beneficial to create an out-of-market tender for emergency demand response? If not, what is your view and why?	
Q15: Do you think it would be beneficial to provide payments to resource providers for any uncleared generation and/or dispatchable demand? If not, what is your view and why?	
Q16: What do you consider to be an appropriate scaling factor to determine the price for residual and why?	
Q17: What is your view on the factors the Authority should consider when valuing the costs associated	

with a standby ancillary service?	
Q18: What other options should be considered to better manage residual supply risk for winter 2024?	
Q19: Do you have information on any other international standby ancillary services and their positive impacts? If yes, please share your information.	

Appendix D: Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ASX	Australian Stock Exchange
AU$	Australian dollars
Authority	Electricity Authority Te Mana Hiko
BESS	Battery Energy Storage Systems
Act	Electricity Industry Act 2010
CAN	Customer Advice Notice
Code	Electricity Industry Participation Code 2010
DDA	Default Distributor Agreement
DER	Distributed Energy Resources
DFS	Demand flexibility service
DR	Demand response
ECRS	ERCOT Contingency Reserve Service
EMA	Energy Market Authority (Singapore)
ERCOT	Electricity Reliability Council of Texas
ERC	Electricity risk curve
ERS	Emergency Response Service
ESO	Electricity system operator (UK)
FCAS	Frequency control ancillary service
GBP	British Pounds
GEN	Grid Emergency Notice
IL	Interruptible Load
KS-9	Kupe gas operation
MDAG	Market Development Advisory Group
MW	Megawatt

NEM	National Electricity Market (Australia)
NPS	Network Service Providers
Regulations	Electricity Industry (Enforcement) Regulations 2010
RERT	Reliability, Emergency Reserve Trader
S$	Singapore dollars
SCADA	Supervisory Control and Data Acquisition
SPD	Scheduling, Pricing and Dispatch
SSAD	Security Standard Assumptions Document
TCC	Taranaki Combined Cycle Power Station
TJ	Terajoule
US$	U.S. dollars
VoLL	Value of lost load
WDR	Wholesale Demand Response
WRN	Warning Notice
$/kWh	Dollars per kilowatt hour
$/MWh	Dollars per Megawatt hour