Driving efficient solutions to promote consumer interests through Winter 2023

Decision

March 2023

1 Executive summary

New Zealand's electricity system manages a fine balance of supply and demand. For the most part, the system works extremely well and delivers a reliable supply of electricity across the country.

Like electricity sectors in other countries, New Zealand's power system has been going through significant change over the past decade. As we transition to an electrified economy and an increased dependence on renewable energy, the system will need to transform to effectively and efficiently manage supply and demand.

The scale and pace of change required means there may be periods of uncertainty and the need to consider and implement short, medium and long-term solutions on behalf of consumers.

Proposing solutions for consumers to manage tight supply

Winter 2023 was highlighted by the system operator as at risk of tight supply situations and linked to the changing nature of the New Zealand power system.

In late 2022, the Authority published a consultation paper – *Driving efficient solutions to promote consumer interests through winter 2023*. The consultation paper described the apparent increase in recent years of trading periods where available electricity supply is tight (or insufficient) compared to projected electricity demand and normal reserve requirements. This is despite *installed* generation capacity keeping up with peak demand, which has been growing after a decade of relatively flat demand.

The Authority's consultation paper focused on such a tight supply situation - a short duration period, such as a morning or evening demand peak, for which there may be insufficient resource offered into the market to meet the forecast demand. These situations occur when there is insufficient time from the published indications of a potential tight supply situation for participants to review their resource offers to the market and act appropriately to avoid a grid emergency.

The paper did not consider other situations which can result in consumers' power supply being reduced or cut, such as the tripping of a large generator or transmission asset or dry winter supply issues. The tripping of a large generator or transmission asset is already managed with the existing instantaneous reserve ancillary service and connected asset owners' Automatic Under Frequency Load Shedding (AUFLS) obligations. Dry winter supply issues are managed through the system operator's monitoring of the Electricity Risk Curves[1] and the Official Conservation Campaign, part of the Electricity Industry Participation Code[2] (the Code) obligations and customer compensation scheme.

It is important to note that if there is a grid emergency situation, regardless of its cause, the system operator falls back on its practised grid emergency management procedures to maintain system security with the resources available at that time[3].

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[1] https://www.transpower.co.nz/system-operator/notices-and-reporting/weekly-reporting/electricity-risk-curves/electricity-risk

[2] Subpart 4 of Part 9 of the Code: https://www.ea.govt.nz/assets/TheCodeParts/Code-Part-9-Security-of-supply-1-November-2022-Real-Time-Pricing1374945.1.pdf

[3] The declaration of a Grid Emergency is a trigger for the system operator to be able to instruct actions from participants, such as the instruction to manage discretionary load by distributors, and direct changes to the configuration of the transmission grid to manage emergency situations. Participants are obligated to comply with instructions from the

Coordinating more intermittent generation with slow start thermal generation

A key reason for the divergence between available and installed generation capacity relates to the increased role of intermittent generation (notably wind), and more expensive gas coal, and carbon emissions.

The increased role of intermittent generation is pushing old slow-start baseload thermal plant to be used more in a peaking capacity. However, it has become very expensive to run thermal plant, eroding the commercial incentive to warm up such plant just in case it is needed to cover brief periods a few times a year.

This has given rise to an operational coordination issue. The concern is not one of overall installed generation capacity, but rather whether, during peak times in winter (when the wind might fall unexpectedly, and it is unusually cold):

- there are appropriate market signals to ensure that there is a sufficient and efficient amount of firm generation running and available to meet peak demand
- demand side participants have the appropriate incentives, information and capability to quickly respond to a forecast shortage by voluntarily shedding, shifting or controlling load
- the system operator has the right tools, systems and processes in place to manage an increasingly complex dynamic between supply and demand side participants.

The Authority has conducted preliminary analysis of the trading periods for which the system operator issued notices indicating tight situations in 2021 and 2022. That analysis indicates that a significant amount of non-thermal generation capacity was on planned outage. This included over 500 MW of hydro generation on average. While this is not a historically unusual level of planned outages for this period, as discussed in the Authority's consultation paper, the operational coordination challenge relating to the commitment of resources, particularly slow-start thermal plant, has changed significantly in recent years.

The Authority will continue to monitor the level and timing of generation outages over winter 2023 to determine whether this is an issue that needs addressing.

Enhancing long term consumer benefit in winter 2023: more and better market information

Consumer interests will be best met if both the demand and the supply side of the electricity system face appropriate market incentives and have the information they need to act on those incentives in real time. Market-based processes will then cause the right amount of electricity to be delivered to the right customers, at the right time and at the right price.

Generators with slow start baseload thermal plant – such as Genesis' coal fired units in Huntly or Contact Energy's large gas fired TCC plant in Stratford – need to make decisions to start up plant and keep it warm some 9 hours (Genesis) to 72 hours (Contact) ahead of when it may be needed. This is an operational constraint as such plants require careful and costly preparation to generate and are primarily designed to run for extended periods or not at all.

To make the decision to commit a unit half a day or more before it is needed, thermal generators need to see strong market signals of potential scarcity with corresponding high spot prices. With more intermittent generation, commercial decisions are being made under increasing uncertainty.

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system operator if they can. This provides the system operator with a level of responsiveness and control of the situation enabling them to minimise the impact of the grid emergency on the wider grid.

To reduce this uncertainty generators need a clear picture of hours-ahead demand and intermittent generation levels, and a clear understanding of the wholesale market pricing impacts of demand response, including controlled demand[4] shedding. The better this information, the less the risk to generators of committing expensive generation when it may not be needed and, conversely, the more likely that such plant is available when needed to meet consumers' demand.

In a similar way, potential providers of demand response need clear market signals to decide whether it is better to control load to avoid potential high spot prices. The Authority's real-time pricing project (RTP)[5] has already implemented a change to spot price calculations to make the price that participants see in real time more reflective of the actual cost to supply electricity.

Additionally, new demand side participation mechanisms (dispatchable demand and dispatch notification) will be implemented on 27 April 2023. These mechanisms will enable the demand side to signal the value of demand response and realise that value through contracts with exposed purchasers.

Over the course of the RTP implementation project, the Authority has engaged extensively with industry on the dispatchable demand and dispatch notification enhancements due for go-live on 27 April 2023. In addition to the series of public webinars hosted by the Authority[6], specific engagement sessions were held with Industry bodies such as the Major Electricity Users Group (MEUG) and the Independent Electricity Generators association (IEGA). Individual sessions with retailers have also helped to publicise the benefits of wholesale market participation following the implementation of the price calculation changes of the RTP project in November 2022. The Authority considers the dispatchable demand and dispatch notification enhancements provided as part of the RTP project as key steps in enabling more dynamic and efficient demand side flexibility and supporting the transition to a low-carbon power system.

The ability of aggregators and retailers to bid their customers' demand flexibility into the wholesale market will allow residential and small industrial consumers to be compensated for the value their resources provide. This could be in the form of reduced tariffs for the portion of their demand that can be controlled or incentive payments from their retailer to allow them to manage the customer's demand at times of high spot prices. As the use of demand flexibility becomes widespread, the overall cost to supply electricity will fall as more expensive generation is displaced by demand response and consumers will receive direct benefit for the flexible resources, such and solar and batter systems or smart EV chargers, they invest in.

If large users, aggregators, or Electricity Distribution Businesses (EDBs) manage load away from peaks and signal their demand management in the wholesale market, they and other consumers can better manage the risk of forced peak demand management.

The Authority is considering what additional mechanisms may be needed to accelerate the development of the demand response market. This will focus on whether demand side flexibility is appropriately rewarded and seek to ensure that all participants face appropriate incentives to

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[4] In the context of electricity, the terms 'demand' and 'load' have been used interchangeably in many publications. Strictly, 'electrical demand' refers to the energy used by consumers directly, while 'electrical load' refers to both the active consumption of energy by appliances and energy consumed by passive components of the electrical circuit e.g. losses due to the heating effect of transmission circuits.

[5] Real-time pricing overview webinars: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/events/real-time-pricing-industry-engagement-sessions/

[6] https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/events/real-time-pricing-industry-engagement-sessions/

find commercial solutions that drive efficient participation of demand response. These issues are addressed in several current pieces of work: Updating the regulatory settings for distribution networks, the Future Security and Resilience work and the Price discovery in a renewables-based electricity system being delivered by the Market design Advisory Group (MDAG).

Eleven options considered to address the size and nature of the problem

Given this context, the Authority consulted on 11 possible options to better manage supply risks for winter 2023. The options seek to improve market information and incentives, consistent with the Authority's statutory objectives.

The Authority's main statutory objective is to promote competition in, reliable supply by and the efficient operation of the electricity industry, for the long-term benefit of consumers. The Authority's additional objective is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers (which only applies to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers). The winter 2023 peak supply risk work undertaken by the Authority, and described in this paper, aligns with all three limbs of the main statutory objective and engages the Authority's responsibility under the additional objective where applicable.

The Authority has considered all submissions made on the Authority's consultation paper as well as additional technical work by the system operator. The Authority applied the following decision framework when assessing all options, as well as having regard to our statutory objectives.

This framework was updated from the consultation proposal following feedback from submitters:

- can the option be implemented for winter 2023
- does the option improve the information available to customers and operators to make efficient contracting and commitment decisions
- does the option better align the incentives on purchasers and operators with the interests of end-use consumers
- does the option pose any risks of unintended harmful side-effects for consumers, such as weakening current incentives to make investments in flexibility resources, or contract to provide flexibility
- can the option be modified or removed if it does not provide a net benefit
- the option aligns with the aim of transitioning to 100% renewables.

Decision on actions to better manage supply risk for winter 2023 and beyond

The Authority has decided on actions to better manage the risk of insufficient generation capacity (or demand response) being made available at times of winter peak demand:

- The Authority will continue to work with the system operator to improve information available on headroom in the supply stack. This will give greater clarity on how tight the supply-demand balance is forecast to be, and so improve decisions to make generation capacity (or demand response) available.
- The Authority will progress nine other potential improvements. Four may be able to be implemented by winter 2023; while the five other options to be progressed are intended to be ready for winter 2024 or beyond.

The options and our decisions are summarised in the table below – a detailed response to each is included in this paper.

The decisions are made within the context of the Authority's statutory objectives with a focus on promoting a competitive, reliable and efficient electricity industry for the long term benefit of consumers. The decisions align with existing work and proposals on future security and resilience, wholesale market competition in the transition and the Market Development Advisory Group's work on price discovery in a renewables-based electricity system.

Summary: options and decisions

Option		Implement or develop further?	Possible by Winter 2023
Information options			
A	Provide better information on headroom in supply stack	Yes	Yes
B	Provide forecast spot prices under demand sensitivity cases	Yes	Yes
C	Improve the accuracy of intermittent generation offers	Yes	No
D	System operator review of wind offers based on external forecast	Yes	Yes
E	Clarify availability and use of 'discretionary demand' control (such as ripple control)	Yes	Yes
Incentive options			
F	Introduce a new integrated ancillary service to offset increased uncertainty in net demand[7]	Yes	No
G	Selectively increase existing ancillary service cover at times to offset increased uncertainty in net demand	Yes	Yes
H	Require retailers to make compensation payments to customers affected by forced power cuts	Yes	No
I	Review administered prices to apply in energy or reserve shortages	Yes	No
J	Introduce hours-ahead market	Yes	No
K	Procure additional resource outside of spot market	No	No

The Authority will not be progressing the procurement of additional resource outside of the wholesale market

Option K involves any solution where payments are made outside the spot market to resource owners to ensure their resource is made available to respond ahead of the need to cut

[7] Demand less intermittent generation supply.

consumers' power supply. For example, this could be by means of an ancillary service that is not integrated with the spot market, as supported by some submitters.

One of the key considerations for the implementation of an ancillary service that is not integrated with the energy market is that additionality is not assured. Instead, it could have unintended consequences as resource that may have responded within the current market arrangements could be incentivised to withhold or withdraw their resource from the spot market to prompt greater payment. Also, without integration into the market system, the impact of operating the ancillary service would not be apparent in the forecast schedules and potentially suppress wholesale prices in real time. This would provide little incentive for other parties to act to avoid the use of the ancillary service. This would not be for the long-term benefit of consumers. Once in place, the ancillary service may also be difficult to modify or remove.

Options proposed in submissions

Several submitters proposed additional options to help manage residual supply risk during winter 2023. The Authority has decided to not progress any of these options for winter 2023. The Authority does note, in the discussion of each proposal, that a number of the proposals are being considered as a part of longer-term enhancements in other work programmes.

One of the proposals considered was from the CEO Forum (a working group of the CEOs of the six larger generators, four largest distributors and Transpower) which generated a level of media interest. The design of this proposal closely mirrors the Authority's Option K. It is an out-of-market payment for resources that would be ring-fenced from other market mechanisms. As mentioned above, a key consideration for the implementation of an ancillary service that is not integrated with the energy market is that additionality is not assured and could have the unintended consequence of incentivising the withholding or withdrawal of resource from the spot market. It would not be apparent in the forecast schedules and potentially suppress wholesale prices in real time providing little incentive for other parties to act to avoid the use of the ancillary service. Once in place, the ancillary service may also be difficult to modify or remove and such a proposal would not be for the long-term benefit of consumers.

The Authority also considers it unlikely the option could be implemented before winter 2023. Feedback provided by the system operator indicated that "significant investigation into its implementation and operability" would be required before it could confirm whether it could implement the option for winter 2023. In addition, a comprehensive Code amendment process would need to be undertaken; the system operator and participants would have to negotiate and implement the technical and contractual requirements.

Other options proposed by submitters are discussed in the main body of the report.

Working together to prepare for the future

We would like to thank everyone who submitted on the consultation paper and consider these decisions will support effective management of winter peak periods in 2023 and beyond and are in the best interests of NZ consumers. The extreme weather events of this year are a timely reminder of the uncertain and often volatile environment in which we operate. We appreciate the insight of industry and interested parties and will continue to engage closely with organisations and individuals to ensure the rules continue to promote a competitive, reliable and efficient electricity industry for the long-term benefit of consumers.

Contents

2 Background and purpose

2.1 Acting on information from the system operator concerning potential risks around peak capacity during time of constrained generation and high demand in winter 2023, on 25 November 2022, the Authority prepared and published its ‘Driving efficient solutions to promote consumer interests through Winter 2023’ consultation paper (the consultation paper). The consultation period closed on 16 December 2022.

2.2 The primary purpose of this follow-up paper is to explain the Authority’s decisions following consultation on options to encourage resource to be made available to respond to tight supply situations during winter 2023, to help ensure the market can discover an efficient level of reliability for the long-term benefit of consumers.

2.3 In considering options to address tight supply situations in winter 2023, the Authority initially assessed both consulted on and proposed options for their likelihood to be implemented in time for winter. So that no time was lost, investigation work with the system operator was started in early January 2023 for those options that the Authority considered could be implemented in time. This investigation work has progressed in parallel with the required regulatory decision process to ensure that the options that the Authority decides to implement can still be implemented in time for winter 2023.

2.4 This paper:

(a) provides the background on the nature of the problem as one of resource availability rather than insufficient installed capacity

(b) outlines the risks of supply shortfalls during winter 2023 that has informed the Authority’s decisions, this includes defining what a tight supply situation is and is not and a recap on what we consulted on

(c) highlights other work the Authority is undertaking that relates to reliability of supply

(d) describes how the options were developed and explaining the Authority’s decisions on which options to progress for winter 2023, including the important role the market has to play in discovering an efficient level of reliability

(e) describes our current thinking on the remaining consulted options as potential solutions beyond winter 2023

(f) explains the Authority’s decisions on options proposed by submitters as well as one additional option the Authority considered

(g) provides an overview of the Authority’s work on demand response market development and

(h) explains the next steps the Authority intends to take following release of this paper.

Efficient levels of reliability

2.5 The following discussion was included in the November 2022 consultation paper *Driving efficient solutions to promote consumer interests through winter 2023.* The concept of efficient levels of reliability is referenced extensively though this decision paper and warrants a summary of the key points for reference when reviewing the option discussions in later sections.

What is an ideal level of reliability?

2.6 Most consumers want a very high level of reliability in their electricity supply given the costs and inconvenience associated with power cuts. Against this backdrop it might be tempting to think 100% reliability is the ideal outcome. However, that is unlikely to be true for most consumers because lifting reliability imposes additional costs that need to be paid for.

2.7 For example, we expect most consumers would be reluctant to pay for an extra set of power poles down their street to improve reliability. That is because the gain in reliability would be very small compared to the very significant additional cost to build and maintain infrastructure that would remain idle almost all the time. Although this example relates to electricity networks, the same logic applies at the generation level. A greater amount of installed generation on the system would be likely to lift reliability, but the gain would need to be compared to the extra cost to establish whether it was worthwhile from consumers' perspective. Put simply, the aim is to minimise the sum of resource provision costs and shortage costs while meeting consumer expectations.

2.8 This approach is reflected in the security of supply standards set out in the Code[8]. These describe the estimated capacity and energy margins where total costs to consumers will be minimised. The standards were developed following extensive consultation and received broad stakeholder support. The accompanying published analysis showed that if the system was achieving the capacity standard, about 16-28 hours of 'shortage' should be expected each year, where shortage means either a shortfall in normal instantaneous reserve cover (the more likely outcome) or forced load shedding (less likely)[9].

Wholesale market seeks to deliver the level of reliability that is valued by customers

2.9 The security of supply standards in the Code are used for monitoring purposes. The actual level of security of supply is determined by the actions of market participants in the wholesale electricity market.

2.10 In essence, resource providers make their investment and operational commitment decisions based on price signals being received from consumers via the wholesale market. These signals come in part from contracts arranged by consumers (or retailers as agents of end-consumers) to cover their expected demand. Consumer demand that is not covered by a contract is exposed to spot prices. At the limit, if there is a reserve or energy shortfall, spot prices will be set to default values intended to reflect the expected value of load curtailment to consumers. It is this exposure to spot prices that incentivises the retailers, on behalf of the consumers, to make efficient market decisions to manage electricity costs. Where consumer resources are used, e.g. the use of domestic battery systems, the retailer should be reflecting that value back to the consumers through reduced tariffs or incentive payments for the use of the resource.

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[8] See Clause 7.3(2) of the Code

[9] See Table 2 of www.ea.govt.nz/assets/dms-assets/14/14134SSAD-2012-v0-6.pdf. The Authority reviewed the standards in 2017 and announced its finding that no change was warranted at that time.

2.11 As discussed further below, current arrangements appear to have delivered satisfactory security of supply for many years and continue to do so. However, there are some recent signs that operational coordination is becoming more challenging with potential adverse implications for reliability. At its heart, the challenges may be due to growing information or incentive problems which make it harder for consumers and providers to strike efficient bargains. These issues are explored further in the next chapter.

A problem of operational availability rather than installed capacity – the operational coordination problem

2.12 While current market arrangements have delivered satisfactory reliability for many years and continue to do so, the system operator has reported that since mid-2021 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. This is despite installed generation capacity keeping up with peak demand, which has been growing after a decade of relatively flat demand.

2.13 A key reason for this divergence between available and installed generation capacity relates to the increased role of intermittent generation (notably wind) and the growing cost of gas, coal and carbon emissions.

2.14 The increased role of intermittent generation is increasingly pushing old slow-start baseload thermal plant to be used in a peaking capacity. However, it has become very expensive to run thermal plant, eroding the commercial incentive to warm up such plant (and incur the costs of doing so) just in case it is needed to cover brief periods a few times a year when wind unexpectedly falls away during a cold winter morning or evening.

2.15 This has given rise to an operational coordination issue. The concern is not one of overall installed generation capacity, but rather whether, during peak times in winter (when the wind might fall unexpectedly, and it is unusually cold):

(a) there are appropriate market signals to ensure that there is a sufficient and efficient amount of firm generation running and available to meet peak demand

(b) demand side participants have the appropriate incentives, information and capability to quickly respond to a forecast shortage by shedding, shifting or controlling load

(c) the system operator has the right tools, systems and processes in place to manage an increasingly complex dynamic between supply and demand side participants.

The Authority has considered the extent of reliability risks for winter 2023

2.16 The system operator expressed concerns about the outlook for winter 2024 based on its Security of Supply Assessment published in June 2022. Subsequently, the system operator expressed concerns for winter 2023 in its *Market insights report – winter review November 2022* which approximated potential market conditions in winter 2023 by assuming they were the same as in winter 2021 and winter 2022 except that the level of peak demand would be increased according to recent trends. The system operator review studied several peak supply scenarios by varying thermal and wind generation. The results of these studies indicated that supply could become very tight in low wind conditions unless most slow-start thermal plant was offered into the market.

2.17 The Authority notes that, based on preliminary analysis of trading periods for which the system operator issued notices indicating tight situations in 2021 and 2022, a significant amount of non-thermal generation capacity was on planned outage, including over 500 MW of hydro generation on average. While this is not a historically unusual level of planned outages for this period, as discussed in the Authority's consultation paper, the operational coordination challenge relating to the commitment of resources, particularly slow-start thermal plant, has changed significantly in recent years. Improving operational coordination to ensure maintenance outages are optimally scheduled represents a significant opportunity to help reduce reliability risks associated with low residual supply. The Authority will continue to monitor the level and timing of generation outages over winter 2023 to determine whether this is an issue that needs addressing.

2.18 The Authority also notes that the apparent upward trend in peak demand is in part due to reduced pro-active demand management following the removal of the Regional Coincident Peak Demand (RCPD) signal with the decision to implement a new Transmission Pricing Methodology (TPM). However, during discussions Authority staff have had with all distributors in 2022, while many distributors indicated that the ripple control technology they have used to reduce hot water load in response to RCPD signals is likely to be supplanted by other technologies in the long-term, no distributors indicated an intention to decommission this technology in the near term. Instead, they generally indicated an intention to retain the technology to manage constraints within distribution networks and/or to make this 'discretionary demand' available to respond when required by the system operator in extremely tight situations. On this basis, the Authority expects that the same level of response will still be available to the system operator in extremely tight situations in winter 2023; for example, as part of the system operator's grid emergency process, demand response from hot water load control will be called upon to help avoid the need to cut power to residential consumers.

2.19 Moreover, the Authority would expect that any distributed generation that is no longer regularly responding to system peaks as they are no longer receiving RCPD incentivised payments from distributors would still be incentivised to respond prior to consumers' supply being disconnected as the RCPD-based price they were previously incentivised to respond to is much lower than the scarcity price at which consumers' power supply is cut off. Using the dispatch notification products being implemented with the final phase of Real Time Pricing (RTP) in April 2023, distributed generators will have reduced barriers to operating in the market, enabling them to offer their generation at a price that ensures they can at least recover their costs and realise the value of their resources.

'Tight supply situations' exclude situations caused by unplanned equipment failure

2.20 The focus of the consultation paper was on developing solutions for tight supply situations arising out of uncertainty in demand and intermittent generation. Events triggered by the immediate failure of generating equipment such as occurred on 23 June 2022 following the failure of a Stratford peaking unit to start and the forced reduction in output of a Huntly Rankine unit due to a mechanical failure, are not considered tight supply situations in the context of the problem definition for this decision paper. It is appropriate in such circumstances that the system operator's grid emergency management processes are invoked. In the 23 June 2022 event, the system operator's grid emergency management processes, revised following the 9 August 2021 demand management event, worked well in maintaining system security and electricity supply to consumers.

The Authority consulted on 11 options to address information and incentive gaps

2.21 The consultation paper proposed 11 potential options to address the incentive and information gaps hindering the commitment of appropriate resources to manage consumer supply during a tight supply situation. 29 submissions were received from a broad range of stakeholders (Appendix A). Options addressing information gaps provide greater visibility of the opportunities and risks associated with potential tight supply situations, increasing incentives to make resource available or to contract for resources to be made available to respond in tight supply situations. In turn, this will reduce the likelihood that consumers' power supply will need to be cut. Options addressing incentive gaps seek to improve incentives on participants and operators directly, to better align with the interests of consumers.

2.22 Of the 11 options consulted on, five are being progressed. Investigation and development work on these options has been progressing since early January with a view to implementation by 1 May 2023 or as near as practicable, subject to final confirmation of the costs and technical constraints of the implementation options.

2.23 The 11 consulted on options are summarised in the table below. Option F was indicated as potentially implementable by winter 2023 in the consultation paper. However, further discussion with the system operator in December 2022 clarified that a market integrated ancillary service, in the same manner as frequency keeping or instantaneous reserves, cannot be implemented by winter 2023 due to the time needed to design, develop and test modification to the market system and associated processes. The system operator considered it would only have been possible to "operationally integrate" a new ancillary service in the time available. That is, implement a stand-alone ancillary service whose use is triggered by an operational setting, such as a potential low residual situation, in the wholesale market. This would not provide the level of integration and efficiency provided by the current instantaneous reserve or frequency keeping markets, as suggested in the Authority's consultation paper, and more closely describes the Authority's option K – procure additional resource outside of the market.

label	Option	Implementable by Winter 2023?
Information options		
A	Provide better information headroom in supply stack	Yes
B	Provide forecast spot prices under demand sensitivity cases	Yes
C	Improve the accuracy of intermittent generation offers	No
D	System operator review of wind offers based on external forecast	Yes
E	Clarify availability and use of 'discretionary demand' control (such as ripple control)	Yes
Incentive options		
F	Introduce new integrated ancillary service to offset increased uncertainty in net demand[10]	No
G	Selectively increase existing ancillary service cover at times to offset increased uncertainty in net demand	Yes

10 Demand less intermittent generation supply.

H	Require retailers to make compensation payments to customers affected by forced power cuts	No
I	Review administered prices to apply in energy or reserve shortages	No
J	Introduce hours-ahead market	No
K	Procure additional resource outside of spot market	No

Other work relating to reliability of supply that is important for winter 2023 and beyond

2.24 Apart from assessing options to address information and incentive gaps to improve operational coordination, the Authority, in conjunction with its service providers, has been undertaking other pieces of work that will help in managing reliability in winter 2023 and beyond. As discussed in the following paragraphs, this work includes completing the real time pricing project, ensuring industry is prepared for a grid emergency situation, reviewing tight situations in 2022, and other work relating to reliability more generally - not just during system demand peaks in the near future.

Complete delivery of real-time pricing demand side market enhancements

2.25 The Authority considers it important to deliver the final elements of the real time pricing project on schedule. The delivery of the dispatchable demand and dispatch notification products at the end of April 2023 will providing a platform for improved signalling of demand response in the wholesale market to assist with operational coordination. This functionality may also be leveraged should the Authority progress to implementation of Option E in its consultation paper in its proposed form – increased visibility of discretionary load - from our November 2022 consultation. The dispatch notification products are expected to increase participation in the market by reducing barriers to entry for small scale and aggregated generation and demand response providers. The Authority has already received expressions of interest from large purchasers and retailers and expects that distributed generation that no longer receives RCPD avoidance-based payments would also benefit from utilising this product to allow those generators to offer at a price that at least recovers their costs of generation. They would then get notified to generate at these times, meaning they can likely operate to help prevent consumers power supply being cut involuntarily. The Authority considers the RTP implementation an important step in enabling future demand side flexibility markets and initiatives, section 8 of this paper discusses how the RTP changes fit into the broader development of demand side flexibility markets.

Review industry preparedness for grid emergency situations

2.26 The Authority and system operator are undertaking measures to ensure industry is prepared for emergency situations. This builds on work the system operator has done in conjunction with the Authority since the 9 August 2021 event, and includes overseeing preparations the system operator is making with other participants to manage potential tight supply situations through winter 2023. Planning has started on the system operator's annual industry exercise, aimed at ensuring industry participants are aware of the actions they would need to take under a grid emergency situation resulting from a tight supply situation that required demand disconnection to manage. Authority staff have engaged with the system operator at an early stage to ensure that the scope of and level of industry engagement in the exercise is representative of a tight supply situation. Staff are mindful of the recommendations following the review of the 2022 industry exercise concerning the need for better distributor communication with retailers and that Transpower continues to improve its broader communication with stakeholders, such as the Minister's office and the Authority during an event. The Authority's compliance team is also undertaking a review of distributors' emergency management preparedness as part of the Authority's pro-active compliance monitoring framework. This will include that distributors are prepared and can act with speed should the system operator require emergency demand management for a short duration event. We intend this review to be completed ahead of winter 2023.

Understand the circumstances and indicators of a tight supply situation

2.27 The Authority is also reviewing the tight supply situations notified during winter 2022 with a view to determining the circumstances of each situation, the resources employed to resolve each situation and the un-utilised resources remaining in the system. The final report on this work will be published in the second quarter of 2023. As mentioned above, preliminary analysis suggests significant resource, not just from plant with extended start times, was un-utilised during tight supply situations in winter 2021 and 2022. Publishing this analysis should demonstrate to industry that there are significant opportunities to commit resource, or to contract for resource to commit, in tight situations.

Ensure long-term market settings are consistent with an efficient level of reliability

2.28 More generally, the Authority has several ongoing workstreams focused on security and reliability. This includes a key focus on security of supply and dry year management, work on considering risks associated with thermal transition, and a large programme of work with the system operator on Future Security and Resilience (FSR). The FSR work will plot the course for operational oversight and improvement by the system operator and is a key multi-year initiative to give increased trust and confidence in the electricity system.

3 The Authority considered several matters when deciding which options to proceed with

The Authority developed options by considering causes of the problem

3.1 The problem was framed in the Authority's consultation paper as one of operational coordination. The Authority defined operational coordination as ensuring resources that have extended start times are committed so they can operate in real time – if this commitment is efficient and for the long-term benefit of consumers (this is often referred to as the unit commitment problem).

3.2 Options proposed in the Authority's consultation paper to improve operational coordination were developed by considering the proximate causes of increased operational coordination challenges, and the underlying cause – information and incentive gaps.

3.3 The proximate causes included:

(a) higher fuel and carbon costs have raised start costs for thermal plant

(b) rising intermittent generation make forecasts more uncertain

(c) changing role of thermal generation means more frequent start decisions for shorter running periods make adequate returns on running increasingly unlikely

(d) the impact on peak demand following the removal of the Regional Coincident Peak Demand (RCPD) charge component of the Transmission Pricing Methodology (TPM)

3.4 In respect of proximate causes, the Authority has undertaken further analysis of the impact of the changes to peak demand due to the removal of RCPD charges. As noted in the Authority's December 2021 consultation paper [11], the RCPD charge incentivised the reduction in peak demand whether or not there were actually any constraints in the transmission system that could benefit from demand management as a means of avoiding or deferring transmission upgrades. Not only were consumers, through the actions of distributors, reducing demand, without helping save overall transmission costs but investments were made in distributed generation, technologies and processes purely to avoid and shift transmission charges to other parties, raising overall costs for no benefit.

3.5 It was indicated by submitters and highlighted by the Authority, that the removal of the RCPD regime would lead to a step change in the rate of increase in peak demand in the near term as grid connected parties stopped inefficiently managing demand for the purposes of managing exposure to transmission charges. The Authority notes that (as discussed in paragraph 2.10), distributors' discretionary demand management assets and processes are likely to remain available in the near-term. Thus, while there may be an apparent increase in peak demand on the system, some of the historical demand response resource will still be available. This is important for winter 2023, and likely 2024, as it is this resource that the system operator currently relies on to avoid consumer disconnection and are only available to use for this purpose under a grid emergency situation.

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[11] https://www.ea.govt.nz/assets/dms-assets/29/Proposed-Transmission-Pricing-Methodology-Consultation-paper-v2.pdf

3.6 The Authority also considers the substantial amount of non-thermal generation capacity on planned outages during winter peaks could be considered as an additional proximate cause. While these amounts may not be abnormal in historical context, they still represent a significant opportunity to increase the proportion of installed capacity that is made available during times of potential tight supply.

3.7 The information gaps included:

(a) forecast accuracy

(b) usefulness of information.

3.8 The incentive gaps included:

(a) under-signalling of shortage costs

(b) lack of clarity around 'discretionary' demand curtailment volumes and use. Distributors' discretionary demand (such as hot water load control) is called upon by the system operator to help prevent the need for cutting consumers' power supply. This response can be significant in size, and if used can significantly decrease prices in real time, but it does not appear in forecast prices

(c) potentially mis-aligned incentives between retailers and end-users if forced load shedding is required.

3.9 The Authority received 29 submissions in response to its November 2022 consultation paper from the parties listed in Appendix A. Submissions are available on the Authority's website at: https://www.ea.govt.nz/development/work-programme/risk-management/winter-2023/consultations/#c19291.

3.10 The Authority received extensive feedback relating to its problem definition and the causes of increased operational coordination challenges, or of increased risks to reliability more generally. These submissions and the Authority's responses are summarised in the following table. A more detailed discussion on each point follows in section 4 of this paper:

Feedback on problem definition	The Authority's view
Extent of reliability risk is greater than suggested by the Authority	The Authority considers that there is an increased potential for tight supply situations over peak demand periods for Winter 2023 if participants do not have appropriate information and incentives. This work is responding to that potential. However, analysis of Winter 2022 tight supply situations has shown that that the system operator used appropriate tools available to it to manage potential tight supply situations under the grid emergency processes, updated following the 9 August 2021 demand management event, and participant obligations already in place. This analysis has also indicated that, incentives to run slow-start thermal plant have changed significantly over recent years. It further

	indicates that the level of planned non-thermal generation outages over the winter period appears unchanged.
Removal of Regional Coincident Peak Demand (RCPD) Charge has or will cause greater reliability risk or operational coordination challenges	The Authority notes that systems used to manage load by distributors are still in place (eg. ripple control hot water systems) and engagement with distributors through the TPM implementation process has indicated that these systems are unlikely to be decommissioned in the near term (as discussed in paragraph 2.10). These resources are used by distributors to manage their own network loads in response to constraints in their distribution network and are still available to the system operator to manage power system load during a grid emergency situation. Thus, while forecast and real-time load has increased following the removal of RCPD payments, the same level of load reduction is also in place should incentives fail to elicit the response of other resources ahead of a grid emergency. What remains is an appropriate incentive for those parties exposed to the impacts of demand management events. The distributed generation resources that typically responded to RCPD signals should respond to spot price signals either as a resource contracted by a spot exposed participant, such as a retailer, or directly via the soon to be introduced Dispatch Notification product.
It's not just a unit commitment problem, also a demand response, and flexibility problem AND Value of reliability differs between types of demand, residential and small industrial consumers value reliability highly	The Authority has considered submissions about the value of reliability differing for different types of demand, with residential and small industrial consumers placing a high value on reliability, along with submissions that demand response and other forms of flexibility are also part of the problem. In response, the Authority's definition of operational coordination has been refined to mean ensuring any installed resource is made available for use (additional response) in real time. Despite this, the Authority considers it important not to lose focus on the extensive

	capacity of generating plant with extended start times (ie, the unit commitment problem). The Authority will continue to monitor the level and timing of generation outages over winter 2023 to determine whether this is an issue that needs addressing.
The problem is about certainty of adequate reliability, not efficient reliability or an information and incentives problem	The wholesale market is designed to yield an efficient level of reliability without burdening consumers with excessive costs and, as discussed previously in this paper, has successfully done so for a number of years. The current concerns over tight supply situations are a characteristic of a power system in transition, as such it is essential that interventions made to support reliability now do not adversely impact the long-term benefit of consumers. In the Authority's view, reframing the problem as a certainty of adequate reliability risks developing solutions which have an adverse impact on the integrity of the market by reducing confidence in the market to deliver optimal reliability outcomes at unnecessarily increased cost to consumers. The Authority considers that no solution can provide certainty of supply. Consider the 23 June 2022 Grid Emergency for example – a Stratford peaker unit failed to start and a Huntly rankine unit reduced its output by 150MW. The situation required discretionary demand management to maintain system security. As discussed in sections 2.5 to 2.11 of this paper, the cost of providing long term standby resource would likely be very high and would result in those resources standing idle for the majority of the time while bringing only an incremental increase in reliability. An efficient market ensures that appropriate incentives are in place to ensure that the costs of increased reliability measures are exposed to consumers at the time they are needed and provides options to efficiently manage that cost where possible.
Amount and type of installed capacity is also part of the problem	The Authority monitors the amount of installed capacity on an ongoing basis – both the current capacity and future capacity that

	is in the development pipeline. The type of installed generation will be a function of the most cost-effective generation technology that can be installed. In July 2022, the Authority commissioned the *generation investment survey* to support the wholesale market review work. This review found that the current developed/ committed pipeline of new investment will have added approximately 780GWh per year of new generation capacity by 2025, representing a 2.5x increase in the historic investment level. The survey also suggested that a further 14,500Gwh per year of generation capacity could be built between 2025 and 2030. While ensuring there is sufficient capacity during Winter 2023 is important, the Authority does not consider this assists with the immediate problem as no additional capacity could be installed in time for Winter 2023.
Issues with scarcity pricing signals	The application of scarcity pricing has become more certain with the introduction of real time pricing in November 2022. However, the lack of a price applied to the use of discretionary demand does affect the price signals during times of potential tight supply. The Authority's option E seeks to address this issue through exposing discretionary demand use to the wholesale market scheduling and dispatch processes.
Lack of appropriate hedge market products and liquidity	The Authority does not consider it possible to make meaningful improvements relating to hedge markets for Winter 2023. While regulation could be put in place, it is unlikely that participants will be in a position to negotiate and enact suitable responses to the regulation in time. The Authority's *hedge market development* program introduced commercial market making provisions in July 2022 to increase hedge market liquidity. The development of further hedge market enhancements, such as "shaped contract products" is being consulted on as part of MDAG's work program, a recommendation paper is expected in mid 2023.
Issues with market power and lack of regulatory threat	As part of the compliance investigation into the 9 August 2021 demand management event, the Authority found that "Genesis'

	behaviour to not offer HLY4 for the evening of 9 August was within the realm of behaviours consistent with that of a rational generator which does not hold significant market power"[12]. However, the Authority does continually monitor the market for signs of market power being exercised and investigates where necessary.
The problem definition would benefit from comment on the expected prices at the time unit commitment decisions were to be made	It would be difficult to draw conclusions from this analysis without knowing the generators' costs, spot market purchase obligations and contract positions at any given time. The Authority continually monitors the market as part of the Authority's functions and investigates when market prices do not align with resource availability. The Authority will consider what further analysis should be included when assessing the need for solutions following Winter 2023.
Options set out in consultation paper are insufficient	The Authority has considered additional options as proposed in submissions. Details of the Authority's consideration are set out in section 7 of this paper. As described in sections 2.24 to 2.28, the Authority has a number of other work streams in progress that seek to address longer-term reliability issues.
Issues with vertical integration	Issues associated with vertical integration are broader than Winter 2023 – for example, the Authority is assessing the extent to which vertical integration is acting as a barrier to entry for new entrants in the market as part of its Wholesale Market Review.
Other points	The Authority appreciates the range and depth of submissions relating to the problem definition and have considered all submissions during option development.

Options must promote the Authority's statutory objectives

3.11 The Authority's main statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those

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12 https://www.ea.govt.nz/code-and-compliance/compliance/decisions/investigations-closed-no-settlement-reached/

consumers (which applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers). Any options proposed for implementation as either a short-term solution for winter 2023 or as a long-term market development, must be consistent with the Authority's statutory objectives.

3.12 The winter 2023 peak supply risk work undertaken by the Authority, and described in this paper, aligns with all three limbs of the main statutory objective and addresses the Authority's responsibility under the additional objective, where applicable. Consideration of alignment with the statutory objective is included in the analysis of each option.

Options that require urgent changes to the Electricity Industry Participation Code 2010 must be consistent with the rationale for making an urgent change

3.13 Any urgent Code amendment must align with Section 40 of the Electricity Industry Act 2010, which enables the Authority to make an urgent Code amendment if it considers that it is necessary or desirable in the public interest that the proposed amendment be made urgently.

The Authority evaluated each proposed option against a set of criteria

3.14 The Authority's overarching aim is to ensure that any changes are for the long-term benefit of consumers. With this in mind, in the consultation paper the Authority evaluated options based on the extent to which they:

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

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

(c) risk unintended harmful side-effects for consumers, such as weakening current incentives to make investments in flexibility resources, or contract to provide flexibility (referred to throughout this document as 'risk of unintended consequences' for brevity), and

(d) can be modified or removed if they do not provide net benefits.

3.15 The Authority also considered the likely time required to implement each option based on current information.

Submitters provided feedback on the Authority's option evaluation criteria

3.16 Submitters were asked whether they agreed with the Authority's proposed evaluation criteria and if they considered there are other criteria the Authority should consider. While many agreed with our criteria, around half of submitters suggested additional or alternative criteria, which we have summarised into key themes in the table below:

Additional criterion suggested by submitters	The Authority's view
Can be implemented through an urgent Code amendment	The Authority agrees this is an important consideration but, where relevant, is already captured by our stated

	consideration of the time to implement each option criterion. For clarity we have decided to make this consideration a specific criterion: '*Can be implemented by winter 2023'*.
Level of reliability	As discussed in the November 2022 consultation paper, the Authority considers the market to be designed to discover the efficient level of reliability. However, there may be information gaps and misaligned incentives that may be leading to suboptimal outcomes at present. The Authority agrees that an efficient level of reliability is desirable for winter 2023. Care should be taken to ensure that an over-emphasis on reliability does not lead to the implementation of options that impose increased costs on consumers for little or no incremental benefit, noting the Authority's earlier point that reliability of supply is never certain. Excessive payments for unnecessarily high levels of reliability will undermine existing products and standards and hinder the emergence of alternative market-based responses (such as demand response) or new technologies.
Helping to ensure confidence in the market and market participants and hinder consumer appetite to decarbonise through increased electrification	The Authority agrees that it is important not to undermine confidence in the market to yield efficient outcomes by imposing increased costs on consumers for little or no incremental long-term benefit. Reduced confidence in market outcomes and market participants could impact consumers' appetite to electrify and decarbonise. With this in mind, the Authority has decided to amend criterion C to make explicit this as an example of an unintended harmful side effect for consumers. Criterion C now reads *'Risk unintended harmful side-effects for consumers, such as weakening current incentives to make investments in flexibility resources, contract to provide*

	flexibility, <u>or undermining confidence in the market</u>'.
Enabling enduring solutions	The Authority agrees that enabling enduring solutions is desirable and has decided to amend criterion D to *"can be modified or removed if they don't provide benefits, <u>and ideally act as an enabler for future solutions or lead to enduring solutions</u>"*.
Simplicity	The Authority agrees that simplicity may be important to the extent it helps determine how achievable an option is by winter 2023. The Authority considers this is sufficiently captured under the criterion '*Can be implemented for winter 2023'*.
Prioritisation – using resources appropriately	The Authority agrees it is important to ensure any limited resource is appropriately prioritised amongst options but does not consider any additional criterion is required as prioritisation is implicit in the criterion '*Can be implemented for winter* 2023' and the overarching criterion that any option must be consistent with our statutory objectives.
Alignment with 100% renewables strategy	The Authority agrees that any solution implemented should align with the Authority's long-term strategy of supporting the transition to a low carbon energy system and so has decided to add a new criterion *'Aligns with 100% renewables'* noting that the '100% renewables by 2030' strategy is a governmental aspiration for the industry.
Taking a principles-based approach: a) Fairness to residential and small business consumers, recognising electricity as an essential service b) Small consumers should not bear the brunt of winter shortages c) Similarly, consumers shouldn't have to pay the costs; windfall profits of generators should be utilised instead.	The Authority appreciates these views and will consider the high value domestic and small business consumers place on electricity as part of assessing whether an option is in the long-term interests of consumers. The Authority will consider which parties should bear the costs for any options that are implemented. The Authority's additional statutory objective also seeks to protect the

	interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. We do not consider any additional criteria are required to capture these points as they are already captured under our statutory objectives.

The Authority reviewed previous winter market notices to determine the potential timing of tight supply situations

3.17 The Authority requested the system operator review the preferred consultation options with a view to their likelihood of implementation by 1 May 2023 or as near as practicable. Alongside the system operator's option assessment, the Authority reviewed market notices issued by the system operator during winter 2021 and 2022. This review aimed to determine start and duration of the winter period most likely to yield conditions that lead to potential tight supply situation.

3.18 In this review, it is important to differentiate between events arising from un-forecast variations in demand and intermittent generation and those caused by the unexpected sudden loss of supply from dispatchable generation or transmission assets. The former situation suggests an evolving situation that participants can react to under normal market processes. The latter situation is more likely to be a sudden onset situation that requires the system operator to immediately take action under its established grid emergency processes.

3.19 A description of each year's notices is provided in Appendix B. When considering the winter period, the frequency and type of notices issued would suggest that the higher risk period falls from late June to early October. Whilst each year has a small number of outlying notices – notably November 2021 and February 2022 neither period could be considered to fall during the "winter" period.

3.20 This high-level assessment suggests that mid-June would be the latest time that options could be implemented and be considered "in time" for winter 2023. Notwithstanding that there may have been periods outside of this timeframe that the system operator calculated residual may have come close to the point of requiring the issuing of a market notice, these periods would appear to be lower risk times where demand peaks have not reached sufficient levels to cause the operational co-ordination issues that the Authority seeks to address with its preferred options. On this basis, options that provide value to the market in incentivising appropriate resource commitment decisions but cannot be implemented by 1 May 2023 may still be progressed if they can be implemented in time for the higher-risk winter period.

4 The Authority has decided to implement one option and further develop four more options to manage residual supply risk during winter 2023

4.1 The system operator has confirmed that certain options around information disclosure are implementable by winter 2023.

4.2 Based on the assessment of each option against the revised evaluation criteria, the feedback from submitters, and the feedback from the system operator, the Authority has decided to proceed with implementation of option A and further development of a four more options to manage consumer supply during a potential tight supply situation in winter 2023. The technical requirements of these four options are being investigated and progressed, subject to a final decision to be made on their implementation in March 2023 for three of the options and April 2023 for one option (option E) requiring urgent Code amendments to implement.

Option label	Option	Implementable by winter 2023?	Will be considered further as part of wider Authority work programme
Information options			
A	Provide better information on the headroom in the supply stack	Yes	-
B	Provide forecast spot prices under demand sensitivity cases	Yes	Yes
C	Improve the accuracy of intermittent generation offers	No	Yes
D	System operator's review of wind offers based on external forecast	Yes	-
E	Clarify availability and use of 'discretionary demand' control (such as ripple control)	Yes	Yes
Incentive options			
F	Introduce new integrated ancillary service to offset increased uncertainty in net demand[13]	No	Yes
G	Selectively increase existing ancillary service cover at times to offset increased uncertainty in net demand	Yes	Yes
H	Require retailers to make compensation payments to customers affected by forced power cuts	No	Yes
I	Review administered prices to apply in energy or reserve shortages	No	Yes
J	Introduce hours-ahead market	No	Yes
K	Procure additional resource outside of spot market	No	No

4.3 These options were all included in the Authority's November 2022 consultation paper. A more detailed summary of these options, including submitters' views, is outlined below.

Option A: Provide better information headroom in supply stack

Summary of option:

4.4 To provide better information to participants the residual offer information, used by the system operator to determine the potential for a "tight supply" situation, will be published

13 Demand less intermittent generation supply.

to the market with the forecast market schedules via a new display provided by WITS[14]. This will provide advance notice to participants of the potential for a “tight supply” situation occurring and allow them to take advantage of the potential opportunity it presents or take appropriate action to manage their exposure to the situation.

What submitters said:

4.5 Over half of submitters were in support of providing better information to participants through this option and no submitters expressly disagreed.

The Authority’s response and decision:

4.6 The Authority has assessed this option based on submitters’ feedback and the revised evaluation criteria and has decided to proceed with it.

Evaluation criteria	Authority view
Improve information availability	The residual offer information is a critical indicator of potential tight supply situations. Publication would provide valuable forecast signals of a potential tight situation and corresponding high prices to market participants ahead of their need to decide to make their resource available for dispatch. The provision of residual information would help inform the likelihood of tight situations occurring and uncover the uncertainty faced by those needing to make advanced decisions.
Better align incentives on purchasers and operators	By providing timely information of opportunities for generators to take advantage of high prices and for demand response to reduce their exposure, more resource is likely to be made available. By uncovering the likelihood of tight situations and the uncertainty in forward schedules, demand participants are more likely to insure against their exposure to high prices or shortfalls by contracting with resource that might not otherwise be made available to respond. These factors would enable increased competition during tight situations as more resource would be made available to respond, leading to a more efficient level of reliability which would help to maintain supply to consumers.
Risk of unintended consequences	Non-participant stakeholders could interpret the published data to mean the power system is closer to tight supply situations more often than is the case in reality. The published residual could start to be used as a “target” for levels of offered resources.
Can be modified or removed or act as an enabler of future development	This option can be simply removed from the WITS displays.

14 Wholesale Information and Trading System – a service provided by NZX under contract to the Authority

Can be implemented for winter 2023	Implementation activity is underway alongside the RTP final software release and will be completed by 27 April 2023 to align with the RTP final phase go-live.
Aligns with 100% renewables	Improved information in the management of uncertainty, in part due to the increase in variable renewable generation, would enable the more efficient implementation of future market enhancements to manage uncertainty and variability.
Meets statutory objective	Publishing residual information provides greater information to the market of potential tight supply situations, facilitating greater competition and improving efficiency as the market is more able to discover an efficient level of reliability. Along with the benefit of enabling more efficient future enhancements to manage the uncertainty associated with increased variable renewable generation, a relatively low risk of unintended consequences and a relatively minimal cost to implement, we are confident this option is for the long-term benefit of consumers.

4.7 The Authority is working with the system operator and NZX (as the WITS manager) to implement this option by winter 2023.

Option B: Provide forecast spot prices under demand sensitivity cases

Summary of option:

4.8 Parallel market schedules illustrating the sensitivity of market conditions to changes in forecast demand will be published, via the Wholesale Information and Trading System (WITS). Price sensitivity information will make it easier for participants to judge the likely price impact of modest variations in wind generation or demand, relative to the central forecast (which will still be provided).

What submitters said:

4.9 Over half of submitters were in support of this option and no submitters expressly disagreed. Aotearoa Energy Resources acknowledged that forecast spot prices under demand sensitivity cases has been provided in the past and is now increasingly relevant and useful information for market participants.

The Authority's response and decision:

4.10 The Authority has assessed this option based on submitters' feedback and the revised evaluation criteria and has decided to further develop it before making decisions on its implementation in March.

Evaluation criteria	Authority view
Improve information availability	The sensitivity of the market schedules to variations in forecast demand provides valuable information as to the value committing additional resources to the market could provide. This information is enhanced through confidence intervals on wind generation forecasts provided in Option D,

	indicating the likelihood of published sensitivity prices. Additionally, the inclusion of the impact on the raw residual generation information would provide information on the potential for a tight supply situation and the approximate level of response needed to avoid one. Over time, the provision of sensitivity schedules would help inform the likelihood of high prices and tight situations occurring and uncover the uncertainty faced by those needing to make advanced decisions.
Better align incentives on purchasers and operators	By providing timely information of opportunities for generators to take advantage of high prices and for demand response to reduce their exposure, more resource is likely to be made available. By uncovering the likelihood of high prices and tight situations and the uncertainty in forward schedules, demand participants are more likely to insure against their exposure to high prices or shortfalls by contracting with resource that might not otherwise be made available to respond. These factors would enable increased competition during tight situations as more resource would be made available to respond, leading to a more efficient level of reliability which would help to maintain supply to consumers.
Risk of unintended consequences	Non-participant stakeholders could interpret the published data to mean the power system is closer to tight supply situations more often than is the case in reality. The published residual could start to be used as a “target” for levels of offered resources.
Can be modified or removed or act as an enabler of future development	This option can be easily stood down should it not provide any value. If the winter 2023 solution proves valuable, it would provide a basis for the design of a market integrated solution.
Can be implemented for winter 2023	System operator has indicated it can implement this option by winter 2023 subject to further development work to confirm design assumptions and investigate development risks
Aligns with 100% renewables	Improved information in the management of uncertainty, in part due to the increase in variable renewable generation, would enable the more efficient implementation of future market enhancements to manage uncertainty and variability.
Meets statutory objective	Sensitivity schedules improve price signals to the market, facilitating greater competition during tight situations and so enabling the market to discover a more efficient level of reliability. Along with the benefit of enabling more efficient future enhancements to manage the uncertainty associated with increased variable renewable generation, a relatively

	low risk of unintended consequences and a relatively minimal cost to implement, we are confident this option is for the long-term benefit of consumers.

4.11 The Authority is working with the system operator to further develop this option for winter 2023, before a decision to implement it (or not) is made in March 2023.

Option D: System operator to publish island aggregate wind generation forecast

Summary of option:

4.12 The system operator currently procures a wind generation forecast to enable its system co-ordinators to make security assessments of system conditions and the likely accuracy of wind generators' offers. If the coordinator determines that a potential tight supply situation may occur and wind generators' offers are materially higher than the generation forecast procured by the system operator, the system operator may call an industry briefing, and highlight the offer discrepancy. This aim is to focus the generators on re-evaluating their offers and ensure they are as accurate as they can be.

4.13 The first notice that participants receive that their offers may need to be reviewed is the industry briefing called by the system operator. By routinely publishing an island-aggregate generation forecast, with confidence intervals to signal the level of uncertainty in the forecast, with participant offers, participants would be able to better assess the potential severity and probability of a tight supply situation earlier. The wind generators would remain entirely responsible for their offers, but the additional information could aid in their decision-making when reviewing their offers or actions they may take with other generation plant in their portfolio.

What submitters said:

4.14 Over half of submitters were in favour of this option. However, some had reservations regarding the option's long-term reliability. Meridian commented on this being a stop gap prior to the earlier options being implemented and considered it should only be progressed for winter 2023 if it is low cost. Meridian's preferred approach is to focus on improving the forecasts of intermittent generation in offers and any code changes that would facilitate this improvement. Some submitters had no view on this option.

The Authority's response and decision:

4.15 The Authority has assessed this option based on submitters' feedback and the revised evaluation criteria and has decided to further develop it before making decisions on its implementation in March.

Evaluation criteria	Authority view
Improve information availability	Providing information on the potential inaccuracy in forecasts would allow participants to improve their wind generation offers. The wider industry would also benefit from a view as to the uncertainty in the forecast schedules due to wind generation forecasts, especially through the provision of confidence indications which can be considered

	in conjunction with price sensitivity information provided through Option B. Over time, participants would gain a greater view of the likelihood of tight supply situations and the uncertainty inherent in forward schedules.
Better align incentives on purchasers and operators	By reducing the uncertainty in forward schedules, participants' decisions that need to be made in advance would be more efficient. By reducing uncertainty, risk is also reduced, resulting in more action by risk-averse parties to make their resource available. By providing timely information on the uncertainty in forward schedules and so of opportunities for generators to take advantage of high prices and for demand response to reduce their exposure, more resource is likely to be made available. By uncovering the likelihood of high prices and tight situations and the uncertainty in forward schedules, demand participants are more likely to insure against their exposure to high prices or shortfalls by contracting with resource that might not otherwise be made available to respond. These factors would enable increased competition during tight situations as more resource would be made available to respond, leading to a more efficient level of reliability which would help to maintain supply to consumers.
Risk of unintended consequences	Intermittent generators could start relying on the system operator forecasts to check their own offers against, leading to a lack of incentive to improve their own market forecasts.
Can be modified or removed or act as an enabler of future development	This option can be removed from the market easily should it not add value. The delivery contract for the system operator forecast will expire at the end of winter 2023 limiting the operational life of the solution. Experience gained from the implementation of this option would provide valuable insight to the level of improvement that could be expected from the Authority's longer term intermittent generation forecasting project.
Can be implemented for winter 2023	An initial assessment by the system operator indicates that this option can be implemented by winter 2023 with some further investigation and development work required.
Aligns with 100% renewables	Improved information in the management of uncertainty, in part due to the increase in variable renewable generation, would enable the more efficient implementation of future market enhancements to manage uncertainty and variability.

Meets statutory objective	The system operator providing forecasts of wind generation to the market allows wind generators to review and potentially improve the accuracy of their offers. By reducing uncertainty, participants are able to make more efficient decisions to make resource available. Greater competition is fostered during tight situations. By reducing risk for risk-averse participants, and by strengthening price signals by revealing uncertainty, greater competition is enabled during tight situation. This, in turn, enables the market to discover a more efficient level of reliability. Along with the benefit of enabling more efficient future enhancements to manage the uncertainty associated with increased variable renewable generation, a relatively low risk of unintended consequences and a relatively minimal cost to implement, we are confident this option is for the long-term benefit of consumers.

4.16 The Authority is working with the system operator to further develop this option for winter 2023, before a decision to implement it (or not) is made in March 2023.

4.17 With respect to Meridian's feedback, the Authority expects this option to be a low cost and therefore low regret option to implement for only winter 2023. The Authority is progressing a separate project that is focussed on improving the forecasts of intermittent generation in the wholesale market as a longer-term objective. The Authority is targeting the publication of an issues and options paper for mid-2023 with a view to implementing any system or market changes by winter 2024.

Option E: Clarify availability and use of 'discretionary demand' control (such as ripple control)

What the Authority said in its consultation paper:

4.18 There is currently poor information available on the level of discretionary demand that network companies can readily curtail if called upon to do so. There is also some uncertainty about who has the right to curtail this load and in what circumstances. In particular, there is uncertainty about when the system operator would call upon network companies to reduce demand.

4.19 When this has occurred in the past, it usually happens close to real time, which does not help with demand forecasting during the time period needed for resource commitment decisions.

4.20 The option would require distributors with discretionary demand control to indicate the availability of their discretionary demand via wholesale market mechanisms when the system operator issues Customer Advice Notice (CAN) advising of a potential low residual situation. This would provide greater visibility on the expected quantity of discretionary demand control in forward schedules, which could assist participants with short-term contracting and commitment decisions.

What submitters said:

4.21 Over half of submitters agreed this is a logical approach, only one clearly disagreed, and many supported this option subject to certain considerations (for example, the need to better understand the intended engagement with distributors before this option is implemented).

4.22 One submitter (Neil Walbran) is concerned this option will add more costs without proposing any ability to recover costs or maintain and develop the underlying equipment. In Mr Walbran's view, a better approach would be to urgently address the lack of incentives for the electricity distribution businesses to maintain and develop the underlying assets (which would require a regulatory change).

4.23 EMH Trade/Bold's view is that this option should not be a priority. In their view, the accuracy of such information will be questionable while there is no incentive on any party to ensure quality of forecasting.

4.24 WEL, Vector, Northpower, and Unison & Centralines also submitted on the need for incentives on distributors to bid in their discretionary demand availability.

4.25 Several submitters provided views relating to the rights and obligations of different parties with respect to the curtailment of discretionary demand:

(a) WEL stated it seeks "absolute clarity" regarding a hierarchy of who and how has the rights to use the demand management and how it is paid for

(b) Mainpower and Electra stress their need to retain the ability to use discretionary demand for their own purposes, while Northpower states that it should only be provided for free to the system operator in an emergency situation

(c) Orion considered that the use of discretionary demand by the system operator should either be incentivised or used as a last resort otherwise distributors bids could distort the market by reducing incentives on market participants to generate

(d) Vector, Northpower, PowerCo, and Unison & Centralines submitted that the rights and obligations between distributors and retailers with respect to the use of discretionary demand is clear, as they are defined in the default distributor agreement.

4.26 There was a range of views expressed by submitters on the ability of distributors to provide information on the level of discretionary demand available to be curtailed in support of system security and what requirements they should have to do so:

(a) Electra noted that it already participates in the instantaneous reserves market, while WEL suggest many network companies may have good visibility of discretionary demand. Orion noted it already provides real time information to the system operator and stated it supports such provision being a requirement on distributors.

(b) Orion, however, stated that forecasting discretionary demand would be challenging for it, let alone other EDBs. Northpower also submitted that forecasting the availability of discretionary demand can be challenging and noted that distributors often use a conservative estimate as a result.

(c) Orion submitted that requiring the use of the dispatch notification product may just serve to add compliance costs without any net gain in reliability, and Electra considered that bidding of discretionary load should not be mandated as that would "shift distributors' focus from contribution to compliance", instead it should be voluntary.

(d) Electra submitted that it did not think there was enough time ahead of winter 2023 for implementation and execution of the dispatch notification product, while Orion also expressed similar concerns without being definitive in its opinion.

The Authority's response and decision:

4.27 The Authority has assessed this option based on submitters' feedback and the revised evaluation criteria and has decided to further develop it before making decisions on its implementation in April following development of associated urgent Code amendments that will be required.

Evaluation criteria	Authority view
Improve information availability	Providing greater visibility of the extent of available discretionary demand management supports the system operator in managing potential grid emergencies. Providing information about the impact of discretionary demand management allows participants to better understand the range of potential prices and the likelihood of consumers supply being turned off. The increase in visibility of discretionary demand management was also a recommendation of the Hodgson[15] report into the 9 August 2021 demand management. The specific recommendation of the Hodgson report related to the provision of real-time information to the system operator. While this information would aid in the real-time management of the power system in the grid emergency situation, it does not address the market incentives issues inherent in not including this information in the scheduling process.
Better align incentives on purchasers and operators	By providing better information on the opportunities for generators to take advantage of high prices and for demand response to reduce their exposure, more resource is likely to be made available. Using the dispatch pricing functionality implemented as a part of the RTP project, this option also results in 'scarcity-like' prices being applied should discretionary demand management be required to maintain supply to consumers. By applying a price to this demand response which would otherwise have occurred for free, there are increased opportunities for generators to capture high prices and for demand response to reduce their exposure. Demand participants would also have greater incentive to contract for resources to be made available to insure against the increased likelihood of scarcity-like prices. These factors would encourage more resource to be made available – increasing competition – during tight situations,

15 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/nvestigation-electricity-supply-interruptions-9-august-2021/

	leading to a more efficient level of reliability to help maintain supply to consumers.
Risk of unintended consequences	Careful management of the order of use of resources would be required to ensure minimal impact on the system operator's grid emergency processes
Can be modified or removed or act as an enabler of future development	Any related Code amendments could be removed (and urgent Code amendments expire after nine months). The lack of financial contracting requirements means that there would be less risk of enduring financial consideration if the obligation was removed. The implementation of this option would provide a valuable insight into the technical and operational requirements for any future demand response market developments.
Can be implemented for winter 2023	An initial assessment by the system operator indicates that this option can be implemented by winter 2023 with some further investigation and development work required.
Aligns with 100% renewables	As the market penetration of variable renewable generation increases in the future as the country transitions toward 100% renewables, participation by demand response in the market is likely to be increasingly important as a source of controllable, flexible, resource to firm variable renewable generation, and to send valuable price signals to the market. This option supports the transition to 100% renewables by acting as an enabler for greater participation of discretionary demand in future demand response markets.
Meets statutory objective	Price signals become more certain by providing information on the extent and impact of discretionary demand management. Price signals are strengthened by assigning a scarcity-like price to discretionary demand that would otherwise respond 'for free' should the system operator require it in a grid emergency. These factors facilitate greater competition and allow the market to discover a more efficient level of reliability. In addition, by acting as an enabler for future use of discretionary demand in the spot market, this option would deliver long-term efficiency benefits. With these benefits and a relatively minimal cost to implement, manageable risks of unintended consequences, we are confident this option is for the long-term benefit of consumers.

4.28 The Authority understands the need to clearly communicate this option with distributors with discretionary demand control to clarify what they would be required to do when the system operator publishes a Low Residual CAN.

4.29 The Authority is working with the system operator and distributors to further develop this option, before a decision to implement it (or not) is made in April 2023, following development of the required Code amendments.

Response to submissions about distributors requiring incentives to bid in their discretionary demand availability

4.30 The Authority intends to further consider whether and how distributors can recover any additional costs they incur in bidding their discretionary demand. The Authority also notes that many distributors are incentivised to act in the best interests of their consumers as these relate to the provision of electricity supply through the distribution networks. The Authority views this option as a potential enabler for future use of distributors’ demand control facilities in the market and will consider as part of solutions beyond winter 2023 whether and how further incentives should be provided to distributors, and other owners of demand side flexibility resources, for the use of this resource in assisting the market in discovering an efficient level of reliability (as discussed in section 8).

4.31 Given the potentially distortionary nature of any incentivised demand response market, the Authority would need to carry out some form of consultation with industry on the design of such a market before implementation. The Authority would also likely be subject to the Government Procurement rules in contracting with participants and may have to run an open tender process, further extending the implementation time. It is also possible, if the cost of the scheme represented a significant increase to the Authority’s appropriation, that a levy consultation would also be required to seek additional funding. This means that the Authority would be unable to implement any incentivised demand response market in time for winter 2023.

Response to submissions about rights and obligations of different parties with regard to the use of discretionary demand

4.32 The Authority does not expect distributors to stop using discretionary demand for their own purposes, only that they signal their use of discretionary demand management and the availability of further discretionary demand for use by the system operator. Discretionary demand management that a distributor intends to use for its own purposes during the tight supply situation, ie, discretionary demand that it intended to manage for its own network requirements, could be signalled at a low price to reflect its more certain probability of management. Discretionary demand that the distributor did not intend to manage could be bid in at a high price to ensure it is used as a last resort prior to the shedding of non-discretionary demand. This signalling would provide a ‘near scarcity’ price should the discretionary demand management need to be enacted. In addition to improving the certainty of scarcity price signals by bidding in demand response that would otherwise be used but not signalled prior to scarcity pricing being invoked, providing a ‘near scarcity’ price would further improve incentives on market participants to commit additional resources or contract for resources to commit at a price that they’re willing to pay.

Response to submissions regarding the rights and obligations between distributors and retailers

4.33 The Authority would like to clarify that it agrees with submitters that the default distributor agreement sets out the rights for use of load control between distributors and retailers.

4.34 WEL networks seeks clarity on the rights to load management to assist with national tight-supply situations and how it is paid for. At this time, the Authority is proposing only that distributors use the dispatch bidding systems as a method of signalling their discretionary demand management availability during a potential tight supply situation – in much the same way that the system operator would currently contact distributors individually to ascertain the same information. The Authority's consultation on *Updating the regulatory settings for distribution networks*[16] is considering how regulatory settings can support distributors with the uptake of flexibility services.

4.35 Distributors would still retain the rights to use the resource for their own network management needs, but any remaining availability that could be called on in a grid emergency would be clearly signalled to the market and the system operator. During a grid emergency, whether discretionary demand has been managed for grid or network management purposes is immaterial; the net effect is the same.

4.36 The Authority considers option E as a potential proof of concept for a future demand response market mechanism. So, while this option may be short lived, the lessons learned from its implementation and use would be invaluable in determining the technical requirements for any future market-based solution.

Response to submissions summarised in 4.26 (b) – (d)

4.37 The Authority has considered some submitters' concerns about the ability for some distributors to forecast and bid their load, and the system operator's preference for conservative estimates of controllable load. The Authority has decided that new obligations on distributors with respect to bid compliance should note the difficulties in accurately forecasting discretionary demand levels and the need for a reasonable estimate of the available resource being exposed to the market. The Authority will further consider whether it would be acceptable to target the obligations for only the larger distributors for winter 2023 to mitigate the risk that resource constraints at the smaller distributors delays the full implementation of this option. The Authority intends to work with distributors and the system operator to develop this option ahead of winter 2023, a decision to implement it (or not) will be made in April 2023.

Option G: Selectively increase existing ancillary service cover at times to offset increased uncertainty in net demand

Summary of option:

4.38 As an alternative to introducing a new ancillary service, the volume of an existing ancillary service purchase quantity would be increased on a selective basis. Increasing ancillary service cover in this way would divert resources from the energy market to manage increased uncertainty and provide a stronger market signal for the need for additional resources at times of tight supply and where there is increased uncertainty in demand and intermittent generation forecasts.

What submitters said:

4.39 Energy Resources Aotearoa and PowerCo agreed this option should be considered for winter 2023. Nova agrees this should be considered if option F (an integrated ancillary service) is not achievable by winter 2023. The Consumer Advocacy Council (CAC) suggests more information is required on this option but that it may be viable provided it is designed carefully and implemented to avoid adverse effects on consumers. The

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[16] https://www.ea.govt.nz/development/work-programme/evolving-tech-business/updating-regulatory-settings-for-distribution-networks/

Major Electricity Users' Group (MEUG) considers work could be undertaken on this option if there was first a check on whether the work was too complex to achieve a robust outcome by winter 2023.

4.40 On the other hand, around half of submitters disagreed or expressed concerns with pursing this option further. The CEO Forum, and its members that submitted individually, preferred its proposed solution of a new multi-hour winter peak ancillary service product with an urgent code amendment.

4.41 The CEO Forum and Transpower submitted their concern with this approach as potentially having unintended consequences. Transpower raises several points in its submission regarding the use of the existing ancillary services. In the case of increasing the procured quantity of instantaneous reserve, it is possible that additional interruptible load could be procured to cover at least some of the increased requirement, however this would not have the desired effect of incentivising increased commitment of generation resources. It would also require load to remain connected to the power system to provide instantaneous reserves when it could otherwise have disconnected in response to high spot prices and reduced the over-all system load. In the case of increased frequency keeping procurement, Transpower also commented that it would need a process for releasing the additional frequency keeping quantity back to the energy market should the desired increase in generation commitment not occur. Transpower also raised concerns regarding the increased operational requirements for its coordinators during times of stress in the control centre.

4.42 Northpower, Vector, Meridian, and Unison & Centralines expressed concerns that the current ancillary services are not fit for the proposed purpose.

4.43 Contact expressed concern that some demand response resource is not capable of participating in the instantaneous reserves market. Nova favours increasing instantaneous reserves cover over frequency keeping primarily because more parties can provide instantaneous reserves compared to frequency keeping. Meridian note that the performance requirement for frequency keeping will prevent many resources form participating.

4.44 Vector expressed concern with increased procurement of frequency keeping as an option because the cost of frequency keeping is not signalled in the energy price.

4.45 Bold Trading's view was that any subjectivity in selective increases in procurement of an ancillary service by the system operator will increase risk and reduce liquidity in the contracts market. WEL Networks, Vector, and Meridian's views were that this option may not result in any improvement, instead simply shifting resource from the energy market to this new ancillary services market.

The Authority's response and decision:

4.46 While many submitters had reservations about implementing option G (selectively increasing existing ancillary service cover), the Authority notes that the existing ancillary services are integrated ancillary services and that several submitters supported introducing a new, integrated ancillary service (Option F). However, as stated in paragraph 2.23 of this paper, the system operator cannot implement a new ancillary service designed under Option F by winter 2023. The Authority also notes that the majority of submitters were in favour of at least one option aimed at improving incentives or otherwise making more resource available.

4.47 The Authority has decided to progress further development of Option G by investigating increasing Frequency Keeping cover in certain situations. In doing so, the ability of the existing contracted ancillary services to manage periods of increased uncertainty would be enhanced and the total amount of capacity required to meet energy and frequency keeping requirements would increase. This change would provide forecast increases in the spot price for energy to reflect the increased need for additional resources and incentivise commitment from these resources into the energy market to manage potential tight supply situations.

4.48 The Authority's assessment of this option against the revised evaluation criteria is as follows.

Evaluation criteria	Authority view
Improve information availability	This option does not improve information availability, but does provide a stronger signal for market participants to make their resource available in tight situations
Better align incentives on purchasers and operators	By increasing the level of frequency keeping and thereby reducing the quantity of offered generation available to the energy market, the likelihood of high prices increases providing greater incentive to generators and demand response to make their resource available to the market. Moreover, thermal generators with extended start times would have less cause for concern that their decision to commit would collapse prices below levels required for them to recover their costs and would have a greater ability to recover operational costs through their offers[17]. Knowing these higher prices will eventuate in certain situations, demand participants would also have increased incentive to contract resource to be made available. These factors would lead to increased competition during tight situations, enabling the market to discover a more efficient level of reliability to maintain consumers' supply.
Risk of unintended consequences	Careful management of the order of use of resources in a tight supply situation would be required to ensure minimal impact on the system operator's grid emergency processes
Can be modified or removed or act as an enabler of future development	Any related Code amendments could be removed (and an urgent Code amendment would expire after 9 months). The lack of additional financial contracting requirements means that there would be less risk of enduring financial considerations if the obligation was removed. The implementation of the increased frequency bands can be performed with existing market system functionality

17 Thermal generators with extended start times will typically offer at least some of their generation quantity (representing minimum run requirements, or the quantity required to recover start-up costs) into the market at low prices once they have made the decision to commit to ensure they are not dispatched off by the market during the period they intend to run. Because this low-priced offer quantity can often be large, commitment of their unit can lead to prices collapsing.

	meaning that it can be applied only when, and for as long as needed. Lessons gained form implementing this work may be useful for further development and potentially implementation of a standby reserve product in the future, as described under Option F.
Can be implemented for winter 2023	An initial assessment by the system operator indicates that this option can be implemented by winter 2023 with some further investigation and development work required.
Aligns with 100% renewables	With increased penetration of variable renewable generation (such as wind and solar) as the economy transitions to 100% renewables, there may be a need to provide a form of standby reserves as a buffer against short-term variations (as described for Option F). This option (option G) would provide valuable lessons in implementing a limited version of this product that would be useful in further considering and implementing Option F in the future.
Meets statutory objective	By providing a stronger price signal for resource to be made available in tight supply situations, competition would be increased, enabling the market to discover a more efficient level of reliability. Given the high value consumers place on reliable supply, if no extra resource is made available the higher energy price that ensues due to the increased frequency keeping requirement is likely to reasonably reflect the value consumers place on the higher probability of shortfall in that situation. In addition, by acting as an enabler for future ancillary services, this option could deliver long-term efficiency benefits. We consider these benefits outweigh the increased frequency keeping procurement costs and the relatively low cost to implement and given risks of unintended consequences are manageable. We are confident, based on current information, this option is for the long-term benefit for consumers.

4.49 In response to submitters who consider this option may result only in swapping resource from one market to another without a net improvement in reliability, the Authority would like to clarify that the intent of this option is to ensure that the existing ancillary services reflect the actual system needs for the service and improve incentives to offer additional resource to the energy market, not to guarantee a pre-determined level of supply reliability.

4.50 The Authority acknowledges that there is a risk of unintended consequences if an existing ancillary service is used to address coordination risk. For example, if the required volume of instantaneous reserves is lifted the increase in reserve requirement may be satisfied by the dispatch of interruptible load providers. This would require the demand associated with the interruptible load to remain connected to the power system and potentially exacerbate the supply situation when they may otherwise have turned off. Increasing the procurement volume of instantaneous reserves could also increase the risk of an over frequency event occurring should a large plant tripping happen, particularly if a large proportion of the extra reserve ends up being procured as interruptible load that operates rapidly in response to a sudden loss of supply.

4.51 The Authority considers it is important to address incentives as well as information and do not consider any other options that address incentives can be implemented prior to winter 2023. The Authority notes that despite 12 submitters disagreeing or having reservations with progressing this option, the majority of submitters did submit in favour of at least one incentive-based option and many submitted in response to question 18 (about whether options A, B, D, and E should be progressed) that it would not be sufficient to only progress these (information based) options. Moreover, several submitters were in favour of Option F, which entails an integrated ancillary service that is a form of standby reserve to manage variations in load and intermittent generation (this is a similar rationale for increasing frequency keeping cover under Option G).

4.52 The Authority recognises that only a subset of resource can participate in the frequency keeping market. The Authority appreciates submissions highlighting this point. If the Authority was able to implement a new ancillary service in time, we would want to further consider submissions on whether different parties should pay. However, given there are limited incentive options available, we consider it appropriate to progress with the system operator further work on this option for winter 2023, before a decision to implement it (or not) is made in early April 2023.

4.53 The Authority notes that any unintended consequences on the market are likely to be limited because the additional frequency keeping requirement would only be invoked during potentially tight supply situations and because in those situations, the market would still be left to determine the efficient commitment of resources.

The market can deliver an efficient level of reliability for winter 2023

4.54 In the Authority's view the market is designed to discover an efficient level of reliability for the long-term benefit consumers without adding unnecessary costs or distorting incentives in other areas of the wholesale market. We consider that it is important for consumers to have confidence in the market and its outcomes to ensure that the transition to a low carbon energy system is not held back or that business practices or technologies are not supported for longer than necessary by inefficient or poorly designed incentives. The Authority considers it essential that the market and its participants can discover an efficient level of reliability at a cost that is in the long-term interest of consumers and that, equally, it can do so without requiring solutions that create significant market distortions.

4.55 The solutions the Authority has decided to implement or further progress for winter 2023 will, if implemented, assist the market in discovering an efficient level of reliability.

4.56 The dispatchable demand and dispatch notification products should also help as demand response will be able to be priced and signalled to the market. Further, distributed generation will be better able to operate during tight situations as it can ensure it can capture its costs and a return on the value of its resource when it operates.

Moreover, these products provide opportunity for parties to more easily contract for additional response, or at least for resource to signal and price their response.

4.57 The Authority notes the significant quantities of resource that have been unavailable during tight situations in 2021 and 2022 includes generation other than that with extended start times. This may be due to generators continuing their historical patterns of maintenance scheduling, developed when thermal generation operated more regularly through the winter period. The system operator monitors the level of planned generation outages through its New Zealand Generation Balance (NZGB)[18] portal. This information is updated monthly and reported to participants and other stakeholders to highlight time periods where the level of planned outages may impact the market's ability to supply the expected demand. The Authority will also continue to monitor the level and timing of generation outages over winter 2023 to determine whether this is an issue that needs addressing.

4.58 Ultimately, to discover an optimal level of reliability for winter 2023, the market will need to make the most of any opportunities to make resource available and to contract for resource to be made available.

5 Longer term market development initiatives

5.1 While options C, F, H, I and J cannot be progressed ahead of winter 2023, the Authority is continuing with related work already in progress as part of the Authority's work program:

Option C: improve intermittent generation forecasts

5.2 A compliance review of Wind generator persistence offer provisions was undertaken in October 2022. This review was initiated in response to concerns raised by the system operator of inaccurate wind generator persistence offers submitted following periods that the output of some wind generators was constrained[19]. Three of the Wind generators have, or are in the process of, updating their persistence offer systems to better reflect the Code requirements that the persistence offer is based on a short-term forecast of the wind conditions and the generator's expected availability and capability[20].

5.3 The Authority is also undertaking a broader review of the forecasting provisions for intermittent generators (i.e., generators of wind and solar energy) in the spot market.

5.4 Inaccurate forecasts by intermittent generators create uncertainty for other participants who need to make decisions about whether to generate or curtail electricity ahead of real time.

5.5 There is a risk that inaccurate forecasts by intermittent generators may result in the following adverse consequences for consumers:

(a) Risks to security of supply: Participants offering to generate too little or consuming more electricity which creates a risk to security of supply and may result in higher costs to consumers from addressing shortages of supply,

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[18] https://customerportal.transpower.co.nz/nzgb/generation_balances#chart=1&term=LONG&scenarioId=default

[19] Wind generation is generally permitted to vary its generation in line with the available wind resource. However, at times of low load and high wind generation, some generators may have their output constrained down to match the available demand. At these times, the generator must reduce and hold its output to no more that the dispatch value provided by the system operator.

[20] See Clause 13.18A of the Code

(b) Inefficient use of resources: Risk of participants offering to generate too much from expensive resources or consuming less electricity than actual conditions would suggest they were able to, and

(c) Inefficiency in forward prices: Spot price volatility leading to higher risk premiums in forward prices.

5.6 The Authority considers it an appropriate time to review forecasting provisions for intermittent generators as the potential adverse consequences are likely to increase as the proportion, amount of, and reliance on intermittent generation increases.

5.7 The Authority is reviewing international intermittent generation forecasting practices and their integration into the relevant wholesale market arrangements. While international markets predominantly rely on centralised forecasting regimes, the method of implementation and the market offer arrangements for the generators themselves vary significantly between individual markets.

5.8 A critical consideration is the technical limitation of the underlying weather forecasts to produce accurate information for the wind generators to base their market offers on over different time horizons ahead of real-time. The project will review the New Zealand intermittent generation offer arrangements and forecasting requirements with a view to ensuring incentives for continuous improvement are assigned to the appropriate parties.

5.9 In our consultation paper we asked submitters whether they agreed that cross-industry work on improving the quality of intermittent generation is unlikely to be available for winter 2023. Most submitters did not provide a view or did not provide a specific view, five agreed, while MEUG and NOVA disagreed as they considered at least some improvements should be achievable by winter 2023. Four of those who agreed, plus two more who did not state a specific view supported this work for the longer term, most expressing it should be progressed urgently or prioritised. Bold Trading considered the focus should be on incentivising improved forecasts rather than focusing on process improvements.

5.10 The Authority has decided not to implement Option C for winter 2023 as discussions with intermittent generators have indicated that, under current forecasting arrangements, there is likely to be little tangible benefit to increasing accuracy or offer update requirements in the short term. Market offers for the majority of intermittent generation capacity are already being submitted at an increased frequency and the remaining capacity is being submitted at a rate that is limited by the forecasting methods being used. Imposing additional obligations on intermittent generators for winter 2023 would provide limited benefit in the time available, even if technical changes by the generators were able to be implemented in time. The Authority’s intermittent generation forecasting project is reviewing both accuracy and frequency of update requirements for intermittent generators as well as forecasting obligations and accuracy requirements. An issues and options paper is due for release in mid-2023 with a view to implementing any changes in time for winter 2024.

Option F: introduce new integrated ancillary service to offset increased uncertainty in net demand

5.11 In our consultation paper we proposed an option of a new integrated ancillary service for ‘standby reserve’ – that is, flexible resource held in reserve, available to respond to unexpectedly large variations in net demand (demand minus intermittent generation such as wind or solar generation). Such an ancillary service may become increasingly relevant as the penetration of intermittent generation increases during New Zealand's transition to a low emissions economy.

5.12 Several submitters expressed that they did not consider, or doubted, that a new integrated ancillary service (Option F) would be achievable by winter 2023, or at least in a sufficiently robust manner that did not compromise its long-term benefits. Most of these submitters supported development of an integrated ancillary service as a longer-term option, post winter 2023, while four submitters supported its development for winter 2023.

5.13 As noted in section 4, the system operator has confirmed that it would not be possible to implement Option F (introduce new integrated ancillary service to offset increased uncertainty in net demand) by winter 2023.

5.14 As such, the Authority is not progressing a new integrated ancillary service to provide standby reserve for winter 2023 but is prioritising this option for investigation as a longer-term option, post winter 2023.

5.15 The Authority considers it important that any ancillary service for standby reserve is integrated into the spot market. An integrated ancillary service allows resource to be offered into both the ancillary service market and the spot market, with resource divided between each market depending on the lowest overall costs (this is known as co-optimisation). This prevents providers from inefficiently swapping between markets as the value of one product varies relative to another. Efficiency would also be fostered by allocating procurement costs of any new ancillary services market to causers where practical.

5.16 Integrating an ancillary service with the spot market allows the energy spot price to signal associated ancillary service costs, where appropriate and practical. This could occur if the next MW of energy, the cost of which sets the energy spot price, increases the demand for the ancillary service.[21] The Authority considers the demand for standby reserve will depend on the uncertainty of net demand and forecast intermittent generation levels. While further work is required to develop options for consultation on exactly how this uncertainty is determined, it may be, for example, that the quantity of net demand in the energy market correlates with its uncertainty and therefore impacts the demand for standby reserve. In this case it may be appropriate for some of the cost of standby reserve to be reflected in the energy price.

5.17 To promote competition in the market and ensure that any new ancillary service does not act as an inefficient subsidy for unproductive plant, we consider a new ancillary service for standby reserve should be technology agnostic and neutral between demand and supply side source of flexibility and integrated with the spot market.

Option H: retailer compensation payments

5.18 Option H involves providing an incentive on retailers to contract for resource to be made available to prevent supply shortfalls by requiring them to pay compensation to consumers should their power supply be cut due to a tight supply situation.

5.19 Approximately half of submitters agreed with the proposal in our consultation paper that this option should not be progressed for winter 2023. In Transpower's view it is unclear if

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[21] For example, the demand for instantaneous reserves is determined by the size of the 'risk', e.g. a large generating unit. If the marginal MW of energy is provided by the risk setter, then the marginal cost of energy includes the marginal cost of the increased instantaneous reserve requirement.

this option would be beneficial, while CAC stated “The Council strongly supports option H due to its potential to incentivise behaviour changes by gen-tailers. However, we believe that this option could only be a partial interim solution. We question how independent retailers, who may not be fully hedged should be responsible to generators. Further investigation is required into how a compensation scheme would work in practice without reducing retail competition in the electricity market”. The remaining submitters provided no view.

5.20 The Authority considers this option should not be progressed for winter 2023 as the benefits of this option may not be realisable in time and it would require careful design to prevent unintended consequences.

5.21 The design of any retailer compensation payments would have to be carefully designed to ensure that the desired outcomes i.e. increased contracting of supply side resources, is achievable and that they will have the desired outcomes for those retailers that take them up.

5.22 Demand side management options available under a grid emergency, by the nature of the situation being faced, must be fast and simple to call on and employ. This means that they do not have the discrimination to disconnect customers of retailers who have inadequately contracted for generation while leaving other customers connected. Without careful implementation, the limitations in demand management technologies could lead to a situation where a customer is disconnected but does not receive a compensation payment because their retailer had adequately contracted for supply while a neighbour receives a payment from their retailer who was not adequately contracted.

5.23 This situation could lead to an undesirable incentive on consumers to move to the under-contracted retailer on the basis that they would receive a compensation payment should they have their supply disconnected through a national tight-supply situation.

5.24 Any customer compensation scheme must be cognisant of the technical limitations facing retailers and their ability to individually influence the impacts on their customers.

5.25 The Authority will review and prioritise, amongst other options, retail compensation payments for further development post winter 2023.

Option I: review administered prices

5.26 Spot market prices are administered, rather than being set based on bids and offers, when there are supply shortfalls for energy or reserves. Administered prices have been set at levels intended to reflect the cost of involuntary load reduction to consumers (if demand is curtailed) or reduced system security (if there is insufficient reserve). The basis for these values, however, have not been fully examined since 2011, although the way they apply was reviewed more recently as part of real time pricing.

5.27 In our consultation paper, we proposed that reviewing these administered prices should not be explored for winter 2023. Many submitters agreed, while NZ Steel suggested progression of this option should depend on how many other viable options there are for winter 2023. Bold Trading disagreed, suggesting that this option is the lowest cost and most quickly implementable option proposed, and the most likely to lead to correct incentives for efficient unit commitment decisions (provided risk transfer conduits exist). Nova also disagreed, suggesting the numbers at least be updated to reflect changes in the Producer Price Index (an indicator of inflation) since 2011. Nova also expressed support for a more detailed review, suggesting that the real cost of power outages is likely to be greater now than in 2011.

5.28 In the Authority's view, the review of the scarcity pricing settings is unlikely to produce a short-term benefit in unit commitment for winter 2023. This is because administered, often referred to as "scarcity", prices in the wholesale market are intended to provide a price signal for the long-term investment in generation resources and allow high-cost generation that only operates infrequently to recover its operating costs when it is needed. The current lower scarcity price for directed demand management at $10,000 / MWh is significantly higher than the current offer levels of the majority of "last resort" generation.

5.29 The energy scarcity prices described in part 13 of the Code[22] have a direct impact on the reserve scarcity prices[23] that indicate a worsening security situation ahead of the need for demand management. Any change to the energy scarcity prices must not only be reflective of any updated views on the value of lost load (VoLL), but must be cognisant of their impact on the value of reserve during scarcity events.

5.30 For these reasons, the Authority considers that it would be undesirable to instigate a change to the scarcity pricing values without a considered evaluation and consultation process. This process would be unachievable within the time available ahead of winter 2023. The Authority is prioritising this review amongst other as a part of its work program for further development post winter 2023.

Option J: Introduce hours ahead market

5.31 As discussed in our consultation paper an hours-ahead market would create a two-stage market settlement process, the first stage via the hours ahead market, and the second via the real-time balancing market where quantities of generation and consumption that differ from those bid and offered into the hours ahead market are settled.

5.32 The advantage of an hours-ahead market is it would improve operational coordination by providing price certainty ahead of real-time. This could be helpful for generating plant with extended start times, as well as battery operators or aggregators looking to plan their charge/discharge cycles, and some demand response providers that need to plan ahead.

5.33 The key drawbacks with hours-ahead markets are that they introduce additional complexity and processes for participants to manage. Some parties also consider that hours-ahead markets unduly favour parties who can readily predict their output or demand, as they can insulate themselves from balancing prices (which like spot prices can be very volatile).

5.34 In our consultation paper, we asked submitters whether they agreed that an hours-ahead market should not be explored for winter 2023. Approximately half of submitters agreed, with only CAC expressly disagreeing, the remaining submitters providing no view or no clear view. CAC opposes an hours-ahead market on the basis that it would add unnecessary complexity to the market and could be detrimental to parties that cannot readily predict their output or demand to balance themselves from volatile balancing prices. Bold Trading and Nova considered that a financial hours ahead market should be explored instead for winter 2023. We respond to this suggestion in section 7 of this paper, which covers options proposed by submitters.

22 Cl13.58AA(2)

23 Cl13.58AA(3) and (4)

5.35 In the Authority's view introducing an hours-ahead market is not an option for winter 2023 as it would take significant time to develop the changes to the market system.

5.36 The introduction of an hours ahead market is already discussed as part of the Authority's wholesale market review and the MDAG 100% renewables work. The Authority considers that it would be unable to implement an hours ahead market in time for winter 2023 and the significant impact on the current wholesale market arrangements, including ASX and over-the-counter contracting arrangements, warrant a considered development and consultation process as part of the wider work program. As noted previously, the MDAG is targeting mid-2023 for the release of its recommendations paper.

6 The Authority will not be considering option K for implementation

6.1 Option K involves any solution where payments are made outside the spot market to resource owners to ensure their resource is made available to respond ahead of the need to cut consumers' power supply. For example, this could be by means of an ancillary service that is not integrated with the spot market.

6.2 Approximately half of submitters agreed with our consultation proposal not to progress Option K (procure additional resource outside of spot market) for winter 2023. However, several of these submitters supported the CEO forum proposal – an ancillary service that is not integrated with the spot market – which the Authority considers falls under Option K. Contact considered this option may be in the best interests of consumers if sufficient other options could not be implemented by winter 2023, while Nova supported it as a simple approach that could be implementable by winter 2023. In NZ Steel's view procuring outside the market could be warranted if there is not a high degree of confidence that the spot market will ensure the lights stay on, while MEUG considers Option K as a potential longer-term solution but that the risk of unintended consequences is high.

6.3 The Authority does not consider it is for the long-term benefit of consumers to implement Option K due to the significant risk of unintended consequences (criterion C) and likely difficulty in modifying or removing it (criterion D)). The Authority considers that procuring resource outside the spot market is not desirable for winter 2023 or as a longer-term option.

6.4 One of the key considerations for the implementation of an ancillary service that is not integrated with the energy market is one of additionality, as discussed in the following two paragraphs.

6.5 The new ancillary service could have unintended consequences due to participants that may have made their resource available within the current market arrangements being incentivised to withhold or withdraw their resource from the spot market. If participants were allowed to choose at each point in time whether to make their resource available to the ancillary service market or to the spot market, and their resource was deemed to be required for reliable supply, they would likely be incentivised to withhold from the spot market in order to prompt a greater payment for their response. At its extreme, this could result in the new ancillary service displacing the spot market in its entirety as all resource providers choose to withhold from the spot market in favour of the more lucrative ancillary services market. Similarly, if the new ancillary service were "ring fenced" for only resource providers not participating in the spot market, resource providers may be incentivised to permanently withdraw from the spot market if higher revenues could be attained in the ancillary services market. In either case, the new ancillary service may undermine incentives, or provide disincentives, for participants to make their response available to the spot market and result in increased costs to consumers to incentivise response at times when they would have responded anyway.

6.6 If the "ring fencing" could be done more strictly, to include only resource providers in the new ancillary service market that definitely would not have responded in any tight supply situation under the current market set-up, the incentive to make response available in the spot market would be impacted less. This incentive would be the same as it is now except during situations where the new ancillary service was called upon, in which case the demand required to be met by resource in the spot market would be lower, reducing prices and so incentives to make response available.

6.7 In any case, an ancillary service designed to ensure sufficient response to achieve a certain level of reliability will also undermine incentives for demand side participants to enter contracts that encourage additional response in tight supply situations.

6.8 A non-integrated ancillary service would also be inefficient compared to an integrated ancillary service in which resource could be made available to the new ancillary service and to the spot market at the same time, with the overall lowest cost combination of resources dispatched across the markets.

6.9 The Authority is concerned that there would be a risk of undermining investment signals in new resource, both generation and demand side flexibility, in the wholesale market if the design of a new ancillary service was rushed or compromised in attempt to implement it in time for winter 2023. The intent of any new ancillary service and the quantum of response required when the product is utilised would require careful design. For example, if the required response reflected an intent to simply ensure sufficient supply (or demand response) to meet demand in tight supply situations, this would risk undermining confidence in the market to deliver an efficient level of reliability (the impact of which on consumers is outlined above). If instead the intent was only to cover short term variability in demand and intermittent generation and the required response reflected the value of providing this service, the spot market would still be primarily responsible for discovering an efficient level of reliability. The Authority is looking to further develop such an ancillary service, as an integrated ancillary service, as part of our work beyond winter 2023 (Option F); for winter 2023 we consider increasing frequency keeping cover under Option G provides a lower cost, lower impact version of this product.

6.10 The Authority is also concerned that there would be a risk that insufficient resources could take part in a new non-integrated ancillary service on technical grounds ahead of winter 2023.

6.11 If such a product were implemented for winter 2023, once supply contracts had been signed, there would likely be significant resistance to the removal of those contracts should the ancillary service be replaced with a more efficient, market integrated, product. This would stifle the development of new markets and technologies to assist in the effective management of increased variability as the New Zealand power system transitions to a low carbon future state with increased variable renewable generation.

6.12 In addition to expected resistance to unwinding financial contracts, once implemented, the ancillary service would become a known quantity in the system operator's security assessments. This would provide a barrier to disestablishing the ancillary service in favour of a new, more efficient product, particularly if the quantity procured has been factored into market outcomes and resource offering strategies.

6.13 Finally, the level of effort required to develop and implement a new ancillary service, including developing technical and contractual arrangements, would be significant. As well as designing the scheme in a way that reduced the risk of distorting existing ancillary service provision, the new product would have to ensure that incentives were placed on additional resource to be offered into the market not just a reallocation of existing resource. This does not include the time needed for the system operator to make any changes to their operational procedures related to the use of the new service and extend training to its full system coordination staff ahead of go-live of the service. This makes it highly unlikely that a solution could be implemented in time for winter 2023. Given the issues described above, the Authority does not consider this option should be prioritised ahead of work already in progress, particularly the final delivery of the RTP demand side enhancements.

6.14 In conclusion, the Authority has decided not to progress Option K for winter 2023. We consider there is a risk of unintended consequences that could lead to reduced competition in the market during tight situations and reduced efficiency as resource is taken out of the wholesale spot market to receive a higher payment in the new ancillary service. There would also be a risk that an efficient level of reliability would not be achievable either because there is insufficient time to ensure sufficient resource can participate or because an inefficiently high level of reliability is procured. Moreover, there is a risk of undermining confidence in the market to discover an efficient level of reliability which could reduce efficiency in the longer term. Given these factors, along with the short and long-term inefficiencies associated with modifying or removing the product, the Authority considers implementing Option K would not be for the long-term benefits of consumers.

7 The Authority received several additional proposals through submissions

7.1 The Authority received additional proposals from:

- The CEO Forum[24]
- MEUG
- Nova Energy and Bold Trading (who submitted a similar proposal)
- The independent retailers[25]
- Ecobulb
- Neil Walbran
- Manawa Energy
- Northpower
- NZ Steel

[24] The CE forum includes CEs from Powerco, Transpower, Mercury, Meridian, Manawa Energy, Vector, Orion, Genesis, Contact Energy, Unison Group, Nova Energy.

[25] Electric Kiwi, Flick Electric, Haast Energy Trading and Pulse Energy

7.2 The Authority also considered a variation of the CEO Forum's proposal intended to better align incentives with the parties better able to affect the availability of resources through a tight-supply situation. These proposals are described below.

7.3 After assessing these proposals, the Authority has decided not to implement or progress them for the reasons outlined below.

CEO Forum's proposal

Summary of proposal:

7.4 The CEO Forum proposed a winter security product be developed using demand response and generation resources. This proposal would require the system operator to develop and implement a new ancillary service, including contractual and technical requirements, ahead of winter 2023.

7.5 The submission included suggested Code amendments and outlined a potential contracting form of an availability fee plus an event fee. The CEO forum pressed for the Authority to decide on developing the proposal by early January 2023 at the latest to allow the system operator time to develop the technical and contractual requirements and tender for the resources. The design proposed that the costs of the demand response program be passed directly to consumers.

The Authority's response and decision:

7.6 Upon receipt of their submission, the Authority assessed the CEO Forum proposal against the problem definition and evaluation criteria in the *Driving efficient solutions to promote consumer interests through winter 2023* consultation paper. The initial review focussed on the completeness and complexity of the proposal as an indication of the likelihood of implementation ahead of winter 2023. However, as discussed below, the similarity in concept to the Authority's consulted on option K, allowed for a more fulsome review in a compressed timeframe.

7.7 While the CEO Forum proposal posits the issue for winter 2023 is one of "unit commitment", the proposal does not seek to address or incentivise increased operational co-ordination, i.e. the commitment of either generation or demand side resources to the market to improve the supply of electricity to consumers. Instead, the CEO Forum proposes contracting for, and ring-fencing, resources to avert the potential for demand management ahead of the established grid emergency processes used by the system operator and industry participants to manage system security issues.

7.8 While the CEO Forum submitted a substantial proposal, significant further effort would be required by the system operator, the Authority and participants to develop and implement the proposal. The development of the technical and contractual requirements of the proposal would require significant effort in a very short timeframe. Given the available resources, it is unlikely that any other option, with the possible exception of option A, could be developed alongside the CEO forum, making the proposal the only option that could be pursued for winter 2023. Aside from the technical development required, the need to develop contractual agreements and negotiate with potential providers in parallel with the technical development introduces significant risk that the solution could not provide the level of resource availability the system operator would be required to rely on in time for winter 2023.

7.9 The Authority met with representative of the CEO Forum following the opening of the Authority's consultation. In that meeting, the CEO Forum advised that it had engaged with a number of potential providers who had indicated that they would be willing to contract on the basis suggested by the proposal. However, in the Authority's view, without a developed suite of technical, contractual and compliance obligations, the actual appetite for participation would be difficult to gauge with any certainty. It was also of note that no cost estimates for the services were provided with the proposal. The potentially open-ended costs associated with contractual negotiation with a single, compelled buyer, such as the position the system would be put in, raise questions as to whether the level of perceived reliability procured would be efficient or for the long-term benefit of consumers. Additionally, once contracts were signed for a given quantity of reserve, and the system operator had taken this reserve into account in its system security analysis, it could become very difficult to unwind the product should a more efficient alternative be proposed at a future time. There could be significant pressure to extend or roll over time-limited contracts to preserve the operating margins those contracts provided, at the expense of investment in more efficient technologies or business practices.

7.10 Feedback provided by the system operator to the CEO Forum in mid-December 2022 indicated that the proposal, as presented at that time, was not in a position to be immediately implemented. The system operator also indicated that, to be able to implement the proposal ahead of winter 2023, the design and all Code amendments would need to be in a final state, ready for the system operator to "accept and implement".

7.11 In its feedback, the system operator raised concerns with aspects of the proposal's suggested Code amendments as well as the operational implementation of the product as it has been designed. The system operator indicated that they would need to "complete significant investigation into its implementation and operability". System operator feedback on the CEO Forum proposal, highlighted concerns with

(1) the proposed compliance regime,

(2) the number of parties the system operator would be required to contract with and

(3) the tools development and participant communications requirements to implement the CEO Forum's proposed operational selection methodology.

7.12 In late December 2022, the system operator noted that the CEO Forum proposal would need to be fully implemented by the end of April 2023 to manage potential tight supply situations in winter 2023. Notwithstanding that Transpower indicated "that the Authority needs to signal a decision around a new ancillary service product by the end of 2022 or, at the very latest, early January 2023" in its submission to the Authority's consultation, the system operator said all design work would need to be completed by, or within, February 2023. The required Code amendments would also have to have been developed and gazetted in the same timeframe. In the following 2-3 months, changes to the system operator's Ancillary Services Procurement Plan and Policy statement could then be developed and consulted upon. Once those have been completed, the tender process for resources would need to be run and contracts agreed. Once contracts had been signed, the system operator would be able to model the ancillary service in their tools and complete any systems changes. In parallel with this work, new operation and support processes would need to be developed and staff trained on their use. As the system operator put to the CEO Forum: "the timing is so tight that we would not want to commit to anything specific without working through the potential pitfalls and resource constraints with you".

The proposal closely mirrors the Authority's proposed option K

7.13 The design of the CEO Forum's proposal is similar to the Authority's consultation Option K. The Authority has the same concerns regarding the efficiency and potential for unintended consequences for the CEO Forum proposal as indicated in the consultation for Option K and discussed in section 6 of this paper. In particular:

(a) resources that may otherwise have offered into the market could be incentivised to withhold their resources to seek higher payments in the ancillary service,

(b) "ring-fencing" the resources for exclusive use in the ancillary service would address some of this concern but, without a link to the wholesale market solution the impact of the ancillary service on the market would be invisible, reducing incentives on participants to avoid the situation that calls for the use of the ancillary service,

(c) without a visible cost of providing the service that is reflective of the resources used at the time of use, there is no benchmark or incentive for participants to invest in alternative contracting or technology options. An "out of market" payment becomes a cost of doing business and embeds technologies and business practices, this would disincentivise the development of more efficient technologies or markets that could reduce costs and

(d) once implemented, the system operator is likely to come to rely on the ancillary service to provide a level of security during peak demand periods, this would become a barrier to removing the ancillary service should a more efficient option be developed. Participants may also be reluctant to forgo the certain payments provided by this option in favour of a more competitive, market integrated, solution.

The Authority's variation of the CEO Forum's proposal: Generator low residual obligation

Summary of proposal:

7.14 The Authority considered introducing a variation of the CEO Forum's proposal that would require generators to bilaterally contract the same resources proposed by the CEO Forum. The generators would be required to contract a volume of demand response equivalent to a percentage of their total installed generation capacity. This percentage would be calculated to provide an efficient level of reserves. Generators would be required to provide evidence of their contract position to ensure compliance.

7.15 These resources would be held in reserve by the generators until a potential tight supply situation was notified by the system operator. The resources would then be bid into the wholesale market at an administered price.

7.16 If the form of the bilateral contracts followed the CEO Forum's proposal, the event fee would provide an incentive for the generator to offer additional generation if it was cheaper to run. The administered price would provide increased price certainty and allow the generators in recover potentially high start-up costs of any additional generation offered in lieu of activating the reserve product resources.

The Authority's response and decision:

7.17 While this option would potentially address the incentives for generators to offer plant capacity, it would not alleviate the same inefficiency and unintended consequences concerns raised generally with Option K of the Authority's consultation and the CEO Forum's proposal. There could also be a risk that bilateral contracts for flexible resources could not be agreed in time for winter 2023. For these reasons, the Authority will not progress development of this proposal.

MEUG's proposal: DC reserve shortage

Summary of proposal:

7.18 MEUG has suggested an option of being able to relax the requirement to procure reserves to cover the loss of either of the two high voltage direct current (HVDC) poles, in situations where this 'n-1' security requirement is constraining HVDC transfer.

The Authority's response and decision:

7.19 Instantaneous reserves (reserves) are primarily procured to cover contingent events, such as the unplanned outage of a generating unit or an HVDC pole.[26] The market system may limit HVDC transfer if the cost of the increased energy being transferred plus the increased reserve to cover that transfer is greater than the alternative – the cost of increased energy from within the island receiving transfer across the HVDC.

7.20 Allowing the HVDC transfer to increase past the level covered by the available reserves would increase the risk of the sudden loss of the HVDC link causing an Automatic Underfrequency Load Shedding (AUFLS) event. An AUFLS event could instantaneously disconnect up to 32% of the receiving Island's load to prevent a potential black out.

7.21 Current scarcity pricing settings, as implemented by the RTP project, allow for the HVDC transfer to be increased above the level that would normally be allowed by the available reserve capacity while balancing the increased risk of an AUFLS event. The reserve scarcity settings are designed to not allow an increase in the risk of a black out.

7.22 If the cost of instantaneous reserves to cover the loss of an HVDC pole was limiting HVDC transfer, the market could create a reserve shortfall, allowing increased energy transfer across the HVDC before an energy shortfall would occur, if this was the least-cost overall solution. This action would be reflected in a reserve scarcity price that would be reflected in the wholesale energy price.

7.23 This means that relaxing the requirement to procure instantaneous reserves to cover the loss of an HVDC pole, without allowing the associated scarcity pricing signal, would be of limited additional benefit and would remove the valuable price signal associated with reserve shortfalls. For these reasons, the Authority will not implement this proposal.

Nova's and Bold Trading's proposal: Day-ahead financial contracts

Summary of proposal:

7.24 As an alternative to introducing a physical hours-ahead market (Option J), Nova suggested that the Authority could facilitate the development of a market for day-ahead peak contracts for difference (CFDs). If the transaction costs can be minimised through using a standard form contract listing through a contracted intermediary, and settled

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26 Instantaneous Reserves are also procured to cover unplanned outages of larger but less probable events categorised as Extended Contingent Events (ECE), in situations where Automatic Under Frequency Load Shedding (AUFLS – load that purchasers are required to shed for ECEs) may be insufficient in preventing widespread blackout events (called cascade failure).

through the Clearing Manager, then generators may have sufficient incentive to offer peak period CFDs on a day ahead basis each day.

7.25 In Nova's view, such a product would enable generators to commit their large thermal units to generate when otherwise the risk of incurring a net loss is too high. Such a proposal would not require any changes to Transpower's Scheduling, Pricing, and Dispatch software but would achieve much the same result as a day-ahead market.

The Authority's response and decision:

7.26 The Authority acknowledges the potential this option has to help reduce the residual supply risk during tight supply situations. However, the Authority has determined that it would not be possible to implement this option in time for winter 2023 due to the complexity of developing a market for day-ahead peak CFDs and the regulatory requirements that would need to be satisfied when introducing a significant new market. As previously discussed in this paper, the MDAG recommendation paper, due mid-2023, will propose any necessary changes to the structure of the contracting market for the long-term benefit of consumers.

7.27 There is also no impediment to parties contracting on a voluntary basis under the current contracting arrangements should both parties see the value in the product. The fact that market participants have not traded day-ahead peak CFDs suggest that considerably more effort would be required to get the market moving if the Authority facilitated the development of a market for these products. This would increase the cost, implementation time and regulatory burden for market participants, which is an undesirable outcome.

Independent retailers'[27] proposal – ensuring all retailers have access to peak hedging products

Summary of proposal:

7.28 In the independent retailers' view, the Authority's past decisions have contributed heavily to the deficient contracting market and the New Zealand market lacks an exchange listed capacity or peak product to create liquidity, a price curve, and equal access to this type of risk.

7.29 The independent retailers' preferred approach is to create a liquid market for hedging with different products that results in high merit order plants being contracted to a relatively high degree for the critical periods. In the short-term, the independent retailers' view is that the best option is to utilise the listed peak products on the ASX, and the Authority should introduce an emergency Code amendment that requires the mandatory market-makers to make some markets in the listed peak-load futures.

The Authority's response and decision:

7.30 The Authority acknowledges the potential this option has to help reduce the residual supply risk during tight supply situations. However, as with Nova's proposal, the Authority is concerned about increase in cost, implementation time and regulatory burden for market participants associated with this option.

7.31 The Authority notes that there is no impediment in the current market arrangements to parties voluntarily entering appropriate peak hedging arrangements. The fact that these

[27] Electric Kiwi, Flick Electric, Haast Energy Trading and Pulse Energy

products are not in widespread use suggests that there are incentive gaps between purchasers and sellers of the products. This implies that significant effort would be required in designing and implementing arrangements to ensure these arrangements are taken up. This could include the need to mandate market making arrangements, as has happened in the ASX forward market for base products. This would require careful consideration and consultation on the market requirements, costs and benefits before the Authority could implement them. The Authority has determined that it would not be possible to implement this option in time for winter 2023. MDAG's *price discovery in a renewables based power system* consultation has considered the development of peak hedging products in its December 2022 consultation, recommendations for which will follow in mid-2023.

7.32 As part of its wider work programme, the Authority will consider whether the current hedge disclosure obligations and risk management information that is collected and published are fit-for-purpose. The Authority will formally seek the sector's view on this later this year.

Ecobulb proposal: LED light bulb roll-out

Summary of proposal:

7.33 Supported by Government funding, all New Zealand homes would receive a voucher for households to get 10 free, latest generation LED energy saving light bulbs. According to Ecobulb, these bulbs last up to 50 years and use up to 90 percent less electricity than the inefficient light bulbs they will replace. This has the potential of cutting the electricity network's winter peak load by 169MW. A report by Concept Consulting calculated a $725 million net present value to New Zealand from this project.

The Authority's response and decision:

7.34 The Authority agrees that this option could be explored further. However, this option does not fall within the Authority's area of responsibility. The Authority were advised by Ecobulb that it is already happening on a regional basis with support from the Energy Efficiency and Conservation Authority. The Authority has recommended to MBIE and EECA consider the benefits of a national roll out of the scheme.

Neil Walbran's proposal: Addressing the lack of incentives for the electricity distribution businesses to maintain and develop the underlying assets

Summary of proposal:

7.35 As outlined previously in this paper, as an alternative to Option E, Neil Walbran suggested the focus should be on urgently addressing the lack of incentives for the electricity distribution businesses to maintain and develop the underlying assets (which would require a regulatory change).

The Authority's response and decision:

7.36 The Authority considers the development of a demand response market and appropriate cost allocation to be for the long-term benefit of consumers. Appropriate incentives would have to be considered not only as to their ability to accelerate the development of a demand response market, but also in terms of their long-term impact on the ability of participants to develop new business practices and implement new technologies. The Authority considers the implementation of the dispatch notification and enhanced dispatchable demand products with the RTP project in April 2023 a valuable step in allowing demand side flexibility to signal the value of its resources, or willingness to pay spot price, in the wholesale market. As indicated earlier in this paper, a number of industrial consumers and retailers have expressed interest in the opportunities that the RTP demand side enhancements will enable.

7.37 Given the available time to address the potential tight supply issues for winter 2023, the Authority does not believe that implementation of a suitable product or service would be possible. The Authority's ongoing work relating to the development of demand response markets is covered in section 8.

Manawa Energy's, Northpower's and NZ Steel's proposals: Providing incentives for owners and operators of distributed generation and demand response during periods of peak demand

Summary of proposals:

7.38 These parties are concerned that since the removal of peak demand charges, owners and operators of resources such as distributed generation and demand response no longer have the necessary incentives or sufficient confidence that they will make a reasonable return on their assets for operating at the time of system need. These parties suggested that an additional incentive needs to be introduced.

The Authority's response and decision:

7.39 In the Authority's view, if there is value in a resource being offered to the market, the owner or operator of this resource can enter into contracts for bilateral supply with retailers. Generators also have access to the wholesale market and can receive dispatch notifications from the system operator. For these reasons, at this stage the Authority does not intend to introduce additional incentives for owners and operators of distributed generation and demand response to provide resource during periods of peak demand. The Authority's ongoing work relating to the development of demand response markets is covered in section 8.

7.40 If an ancillary service is needed to address additional reliability concerns that these resources could offer into, that product would best be developed as an integrated ancillary service to the wholesale spot market.

8 Authority to consider incentives for DR market development

8.1 The rate of installation of renewable generation and industrial electrification is accelerating. It may be that the uptake of demand side participation does not keep pace due to maturity of the technology or business process necessary to take part. In this case, the Authority could consider limited incentives to take part.

8.2 Approaches that empower consumers by enabling demand to be more responsive to price can be very effective at mitigating market power.

8.3 As discussed earlier in this paper, the implementation of dispatchable demand and dispatch notification through the Real Time Pricing project in April 2023 will enable the participation of smaller purchasers as dispatchable demand (ie, enable smaller purchasers to participate in the wholesale market and respond to market conditions in a similar way as generators).

8.4 Over the course of the RTP implementation project, the Authority has engaged extensively with industry on the dispatchable demand and dispatch notification enhancements due for go-live on 27 April 2023. In addition to the series of public webinars hosted by the Authority[28], specific engagement sessions were held with Industry bodies such as the Major Electricity Users Group (MEUG) and the Independent Electricity Generators association (IEGA). Individual sessions with retailers have also helped to publicise the benefits of wholesale market participation following the implementation of the price calculation changes of the RTP project in November 2022. The Authority considers the dispatchable demand and dispatch notification enhancements provided as part of the RTP project as key steps in enabling more dynamic and efficient demand side flexibility and supporting the transition to a low-carbon power system.

8.5 Demand flexibility services would also support increased demand response participation – these reward consumers for allowing a service provider to remotely control their electricity-intensive equipment and batteries to shift or reduce electricity use in response to market, grid, and local network conditions.

8.6 The Authority's work-programme includes key workstreams aimed at enabling innovative solutions to promoting competition and empowering consumers to participate in the electricity market in new ways.

8.7 The focus of much of this work is about addressing barriers to entry and innovation, and the Authority considers these therefore remain highly relevant to the promotion of wholesale market competition in the transition toward 100% renewable electricity. For example, the Roadmap covers work on:

(a) MDAG's work on market operation and investment with 100% renewable electricity

(b) the entry of new technologies (like batteries to participate in the reserves market)

(c) barriers to connection and operation of renewable generation

(d) addressing first mover disadvantages (via the TPM)

(e) the implementation of real time pricing and enabling the participation of flexible distributed demand

(f) the Innovation and Participation Advisory Group's (IPAG) advice on flexibility trading and equal access

(g) review of the range of risk management tools available to purchasers and sellers in the wholesale market.

8.8 The Authority will investigate what other mechanisms may be needed to accelerate the development of an efficient demand response market. Conceptually, increasing demand participation looks to be capable of providing solutions that are consistent with the evaluation criteria, though that would need to be determined based on specific proposals.

8.9 In considering any additional mechanisms, the Authority will first need to clarify the market or regulatory issues that may be holding back the development of the demand

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[28] https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/events/real-time-pricing-industry-engagement-sessions/

flexibility services (noting MDAG's prior work on this in the context of a renewables-based electricity system, and the options it is consulting on).

8.10 The Authority is also cautious about providing out-of-market payments as they could interfere in the still small market, undermine current investments in demand response and so discourage investment, innovation, and competition.

8.11 The Authority would also be subject to the Government Procurement rules in contracting with participants and may have to run an open tender process, further extending the implementation time. This means that the Authority would be unable to implement any incentivised demand response market in time for winter 2023.

9 Next steps

9.1 The Authority will continue working with the system operator, NZX and distributors to implement option A and progress options B, D, E and G so that a decision on their implementation (or not) can be made and clearly communicated to market participants ahead of winter 2023.

9.2 This development work will include preparing any required Code amendments.

9.3 For the options that cannot be implemented by winter 2023, the Authority has either already projects in progress as part of its work program or will prioritise their development in the Authority's work programme following winter 2023.

Appendix A List of submitters

Submitter	Category
Contact Energy	Generator-retailer
Genesis Energy	Generator-retailer
Meridian Energy	Generator-retailer
Nova Energy	Generator-retailer
Mercury Energy	Generator-retailer
Manawa Energy	Generator
Transpower (System operator)	System operator
Electric Kiwi, Flick Electric, Haast Energy Trading and Pulse Energy	Independent retailers
Vector	Distributor
Wellington Electricity	Distributor
WEL Networks	Distributor
Orion	Distributor
MainPower	Distributor
Northpower	Distributor
PowerCo	Distributor
Electra Energy	Distributor
Unison Networks & Centralines	Distributor
CEO Forum	Chief executives from a range of generator-retailer companies and distribution networks
Major Electricity Users' Group	Commercial industry representative group
Electricity Networks Association	Network firms' representative group
Energy Resources Aotearoa	Energy intensive businesses' representative group
Consumer Advocacy Council	Advocate for residential and small business electricity consumers
New Zealand Steel	Major electricity user
solarZero	Solar energy company
Ecobulb	Lighting company
Bold & EMH Trade	Financial intermediary
Aotearoa Energy	Business consultancy
Neil Walbran Consulting	Business consultancy
Member of the public GDW	Business consultancy

Appendix B Low residual market notice review

A.1 2021 market notices

Month	Period the notice(s) applied to		Initial notice	Sent	Extenuating circumstances
July	12 July 5.30pm-7pm	Evening	CAN	5hrs before	-
	13 July 5.30pm-7pm	Evening	CAN	8.5hrs before	-
	14 July 7:30am-10am	Morning	WRN	1.5hrs before	-
August	03 August 6pm-7pm	Evening	WRN	2.5hrs before	-
	05 August 5.30pm-7pm	Evening	CAN	3hrs before	-
	08 August 6pm-7pm	Evening	WRN	1.5hrs before	-
	09 August 5:30pm-9pm	Evening	CAN	11hrs before	None (1 WRN sent 4.5hrs before 1 GEN sent 1hr before)
	10 August 07:30am-8.30am	Morning	CAN	10hrs before	None (1 WRN sent 3hrs before 1 GEN sent 1h before)
	10 August 5:30pm-7:30pm	Evening	CAN	8hrs before	-
	17 August 5pm-7:30pm	Evening	GEN	0.5hrs before	HVDC pole outage
	18 August 8am-9am	Morning	CAN	15hrs before	-
	20 August 6pm-7pm	Evening	CAN	23hrs before	-
September	1 September 6pm-7pm	Evening	CAN	5hrs before	-
November	22 November 3:30pm-7pm	Evening	CAN	4.5hrs before	-

A.2 2022 market notices

Month	Period the notice(s) applied to		Initial notice	Sent	Extenuating circumstances
February	21 February 1pm	Midday	CAN	17.5hrs before	-
	21 February 3.30pm-5.30pm	Evening	CAN	20hrs before	-
June	23 June 7.54am-9.30am	Morning	GEN	4mins into period	Stratford peaker + Rankine faults
	28 June 5pm-7.30pm	Evening	CAN	1.5hrs before	-
July	5 July 5pm-7pm	Evening	CAN	4hrs before	-
August	12 August 7.30am-9am	Morning	CAN	17.5hrs before	-
September	6 September 6pm-7.30pm	Evening	CAN	7hrs before	-
	7 September 7.30am-8.30am	Morning	CAN	2hrs before	-
	14 September 5.30pm-7.30pm	Evening	CAN	24hrs before	-
	15 September 7.30am-9am	Morning	CAN	22hrs before	-
October	4 October 8am-9.30am	Morning	CAN	5hrs before	-
	7 October 7.30am-9am	Morning	CAN	16.5hrs before	HVDC filter trip (WRN sent 2 hrs before GEN sent at the time of the event)