Driving efficient solutions to promote consumer interests through winter 2023

Consultation paper

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Submissions close: 16 December 2022

1. Executive Summary

Wholesale market seeks to deliver the level of reliability valued by consumers

Current arrangements seek to ensure consumers get the level of reliability they want and are willing to pay for. The arrangements appear to have delivered satisfactory reliability for many years and continue to do so. However, since mid-2021 the system operator has reported 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* capacity keeping up with peak demand, which has been growing after a decade of relatively flat demand.

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

These factors are increasingly pushing old slow-start baseload thermal plant to be used in a peaking capacity. However, this changing role of baseload thermal plant, coupled with increased warming and idling costs, is eroding the immediate commercial incentives to warm up that slow-start thermal plant (particularly the Huntly Rankine units) hours ahead just on the chance that wind unexpectedly falls away during a cold winter morning or evening.

Further, as the plant ages its useful running life and remaining start-up opportunities reduce. This also complicates the trade-offs for firms about whether to use the plant's remaining operational hours when profitability is uncertain. (The lower the likelihood of low wind conditions at peak times, the less likely it is that warming up slow-start thermal plant will be profitable, all else equal.)

These effects have given rise to what some market participants call a 'unit commitment problem' – an operational coordination issue. The issue is more fundamental, though. It is an inherent part and consequence of the transition toward 100% renewables. Investment in new flexible generation and demand response solutions are needed.

As that transition occurs, it is important that the regulatory system continues to provide the appropriate incentives for efficient balancing of supply and demand, in a way that promotes the long-term interests of consumers.

Concerns that some generation is not available at peak times

System operator grid notices indicate an increase since mid-2021 in the frequency of trading periods where *available* supply is extremely tight (or insufficient) compared to projected electricity demand and normal reserve requirements.[1] While the number of hours of reserve or energy shortfall remained below the level[2] accepted as economically optimal in New Zealand's capacity adequacy standard, the apparent upward trend does raise some questions.

In particular, the increased frequency of tight balance between supply and demand is not because the margin between installed supply capacity and peak demand has narrowed appreciably. On the contrary, the North Island Winter Capacity Margin has remained well above 1,000 MW since 2012.

This highlights that it is not total generation capacity but availability of sufficient flexible generation (and demand response) at peak times that has been the issue.

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1 See Figure 1 showing grid notices issued to indicate very tight supply or shortages of various types.

2 Pg11 of Security Standards Assumption Document https://www.ea.govt.nz/assets/dms-assets/14/14134SSAD-2012-v0-6.pdf

At such times it would be useful to have slow-start thermal units available, but that has appeared to be not commercially viable under current contracts and market settings.

The system operator (Transpower) has also been expressing concerns about the outlook for winter 2024. Referring to its Security of Supply Assessment published in June 2022, the system operator suggested that that under certain scenarios the winter capacity margin could fall under the security standard in the Code as early as 2024.

The system operator subsequently undertook further analysis and issued its *Market insights report – winter review November 2022*. That report sets out system operator concerns that tight peak supply conditions may be more prevalent in winter 2023 than indicated in its June 2022 Security of Supply Assessment.

Proximate and underlying causes of winter peak challenges

The proximate causes of the rising winter peak challenges appear to be increased uncertainty around peak demand, higher impact of un-forecast intermittency with over 1GW of wind generation now installed, and higher warm-up and idling costs for slow-start thermal units. However, these factors alone should not cause sub-optimal outcomes. The expectation of earning high spot prices when system conditions are tight should create incentives on operators to make plant available, provided consumers value the incremental reliability and are willing to pay the extra costs.

The above factors point to a need to consider whether there are underlying incentive and information gaps that hinder the emergence of efficient generation and demand response decisions to balance demand and supply, and appropriately manage security of supply risks. The Authority has considered this question and identified some potential gaps and concerns in this area. These include unreliable demand and wind forecasts, lack of clarity around the size of 'discretionary' demand (e.g. ripple control) and how it will be managed, and potentially misaligned incentives between retailers and end-users if forced load shedding is required.

The Authority considers it prudent to examine options to resolve these potential information and incentive gaps before winter 2023, if possible, especially given the apparent deterioration in operational coordination observed in the last 15 months. Any potential measures would need to be for the long-term benefit of consumers, consistent with the Authority's statutory objective.

Options to better manage supply risk for winter 2023

Table 1 of this paper sets out an initial set of possible options to better manage supply risk for winter 2023. The list is not exhaustive, and there may be other options available to promote consumer interests. The Authority welcomes sector feedback on other potential approaches but paramount in its consideration of options has been a concern to ensure that any change will be in the long-term interest of consumers.

An initial set of options that appear most attractive based on this objective and current information are:

- Providing more reliable information to wholesale market participants on the extent of headroom in the supply stack
- Providing forecast spot prices under sensitivity cases (different demand forecasts)
- Enabling the system operator to review wind offers based on an external meteorological forecast and invite wind operators to reconsider their offers if there are large divergences
- Clarifying the volume of discretionary demand (e.g. ripple control of hot water not offered for interruptible load) in forward schedules and how it could be called upon by the system operator.

In addition, there may be net benefit from introducing a new ancillary service, or selectively lifting cover for an existing service, to counter the effects of greater peak demand uncertainty and supply intermittency, and to potentially incentivise more generation (or potentially demand response) to offer into the market during peak periods. These ancillary service options could provide more assurance of reducing residual supply risk, but also have greater likelihood of raising supply costs paid by consumers. It is unclear whether the benefits would exceed the costs and hence the case for these options is less clear cut and would require more analysis. Such options would also be likely to have greater implementation challenges before winter 2023.

The Authority has also identified some other options it does not propose to pursue further for winter 2023, although some may be attractive for consideration at a later date.

Next Steps

The Authority has sought to describe the options in sufficient detail to allow stakeholders to provide meaningful feedback. The Authority recognises stakeholders might prefer to see more detail for some options, or other options presented for consultation. However, that would have meant delaying the release of this paper until early 2023. That in turn would risk not optimising the opportunity for feedback to influence the shape of any options adopted before winter 2023. Stakeholder feedback is sought not only on the options outlined in this paper, but any other approaches that may be available to the Authority for the long-term interests of consumers.

While the focus in this consultation is winter 2023, the Authority also invites stakeholder views on medium term issues and options.

Following consideration of feedback on this paper, the Authority will refine any options that it would seek to progress. If the Authority decides to progress any option that would require a Code amendment, it will endeavour to consult further with stakeholders if it is practical to do so. However, it is possible that the timelines to allow implementation before Winter 2023 may make that impractical. If there is insufficient time to allow for consultation on a specific Code amendment and the relevant statutory requirements were satisfied, the Authority could consider making an urgent Code amendment under section 40 of the Electricity Industry Act.

Contents

2. What you need to know to make a submission

What this consultation paper is about

2.1. This paper describes a range of potential options to better manage potential risks to balancing supply and demand for winter 2023. Some of the lower cost and risk options are already being investigated for possible implementation, subject to the outcome of this consultation and any further steps required. Others require more analysis to assess, and some may not be practically feasible for winter 2023.

2.2. We are particularly interested in more detailed feedback on options proposed for introduction before mid-2023 as a first step, as they will need to be progressed quickly to be available by that time.

How to make a submission

2.3. The Authority's preference is to receive submissions in electronic format. Submissions in electronic form should be emailed to WholesaleConsultation@ea.govt.nz with 'Options to reduce operational coordination risk – consultation paper' in the subject line.

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

(a) indicate in a cover note which part/s should not be published;

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

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

2.5. If you indicate there is part of your submission that should not be published, the Authority will discuss with you before deciding whether to not publish that part of your submission. However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. The Authority will consult with you before releasing any material that you have said should not be published.

When to make a submission

2.6. Please deliver your submissions by 5pm Friday 16 December 2022.

2.7. This deadline allows three weeks for submissions. The Authority will acknowledge receipt of all submissions electronically. Please contact WholesaleConsultation@ea.govt.nz if you do not receive electronic acknowledgement of your submission within two business days.

Further information

2.8. Please direct any specific questions or queries to: WholesaleConsultation@ea.govt.nz

3. Reliability standards reflect consumer benefits

3.1. This section briefly recaps on the factors that affect reliability and describes why the ideal level of reliability should reflect consumers' preferences[3] and benefits.

Necessary pre-conditions to achieve reliable supply

3.2. To provide reliable electricity supply to consumers, four pre-conditions must be met:

(a) Sufficient supply resources[4] must have been *installed* ahead of time to serve total demand.

(b) Resources dependent on a storable fuel (e.g. water, coal, gas etc) must have sufficient inventory to operate when required.

(c) Resources that have extended start-times must be committed so they can operate in real-time. This is also referred to as operational coordination.

(d) There must be sufficient capacity in transmission and distribution networks to convey electricity from supply sources to the points where it is consumed.

3.3. Items (a), (b) and (d) are regulated through the Commerce Act and the Code and are not considered further in this paper. The Electricity Industry Participation Code (Code) is designed to ensure that items (a) – (c) are achieved in a way that is consistent with the longer-term interests of consumers via efficient market signals (prices), risk management markets and obligations on asset owners and the system operator.

3.4. The balance of this paper focuses exclusively on ways to ensure 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 also referred to as operational coordination (item (c) above).

What is the ideal level of reliability?

3.5. 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.

3.6. 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.

3.7. This approach is reflected in the security of supply standards set out in the Code.[5] 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

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[3] A more complete description of the Authority's interpretation of the reliability limb of its statutory objective can be found in *Interpretation of the Authority's Statutory Objective:* https://www.ea.govt.nz/assets/dms-assets/9/9494statutoryobjective.pdf

[4] This includes generation, storage batteries or sources of demand-side flexibility.

[5] See clause 7.3(2) of the Code.

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).[6]

3.8. The level of shortage in recent years has been well below this level. In the first 10 months of 2022, there were 2.25 hours of reserve or energy shortage. In 2021, during which load was disconnected on 9 August, system operator reports indicate there were 6 total hours of shortage. There were no periods of reserve or energy shortage from 2018 to 2020.

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

3.9. 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.

3.10. 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.

3.11. 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.

[6] 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.

4. Apparent increase in occasions of tight conditions

4.1. Since mid-2021, notices issued by the system operator indicate there has been an appreciable increase in the frequency of trading periods where *available* supply is extremely tight (or insufficient) compared to projected electricity demand and normal reserve requirements.[7] This change has occurred despite the *installed* capacity margin remaining fairly stable over time.[8]

4.2. In short, there are signs of a greater likelihood that some installed generation resources may not be available when needed, or that the level of resource available (in particular controllable discretionary demand) may not be clear to the system operator. This chapter explores this issue and possible underlying causes.

Providers decide what resources to make available before real-time based on forecasts of their value to consumers

4.3. New Zealand's electricity system (like many others) currently uses a 'self-commitment' approach to coordinate availability decisions. Providers of generation, demand-response and storage capability each decide how much of their resources to make available to the system prior to real-time. We refer to these choices as *commitment decisions*.

4.4. As outlined in Chapter 3, current arrangements seek to encourage operators to make resources available for supply if doing so will be valuable to consumers. Put simply, these arrangements are designed to ensure consumers get the level of availability (and hence reliability) they want and are willing to pay for.

4.5. To help with overall coordination of resources, all major resource providers must signal their prevailing plans by submitting offer information into forward schedules generated in the run up to real-time. This information includes tranches of resource volumes that will be available at different prices. The market system processes this information to generate spot price forecasts. The schedules and forecasts are progressively updated as real-time approaches.

4.6. Forecast spot prices indicate the revenue operators will likely earn if their resource is called upon in real-time. There are no availability payments per se in the spot market. However, resources that are not available will earn no spot revenue. Hence, there is an incentive to make a resource available if the forecast revenues exceed start-up and running costs. Purchasers can also affect operators' commitment decisions, because the presence of forward contract sales can make operators more likely to commit a resource to be available.[9]

4.7. The final deadline for resource providers to submit offers is 'gate closure' one hour before real-time[10]. Forecasts issued this close to real-time are typically reliable. However, some resource providers need to make their commitment decisions much earlier than gate closure. For example, some thermal units can take up to 12 hours to start from cold and face appreciable start-up costs. Commitment decisions for such resources need to be made based on earlier forecasts that have greater uncertainty.

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7 See Figure 1 showing grid notices issued to indicate very tight supply or shortages of various types.

8 See Figure 2 showing the North Island capacity margin since 2017.

9 These can be bilateral contracts, exchange traded, or fixed price sales to retail end users (i.e. vertically integrated sales).

10 There are some exceptions, such as faults, unexpected fuel issues etc – known as *bona fide reasons*

System operator coordinates available resources in real-time

4.8. The system operator coordinates available resources in real-time with the goal of serving all demand and ensuring sufficient reserves are on standby to cover pre-defined risks (such as the unexpected loss of the single largest generator or transmission circuit).[11]

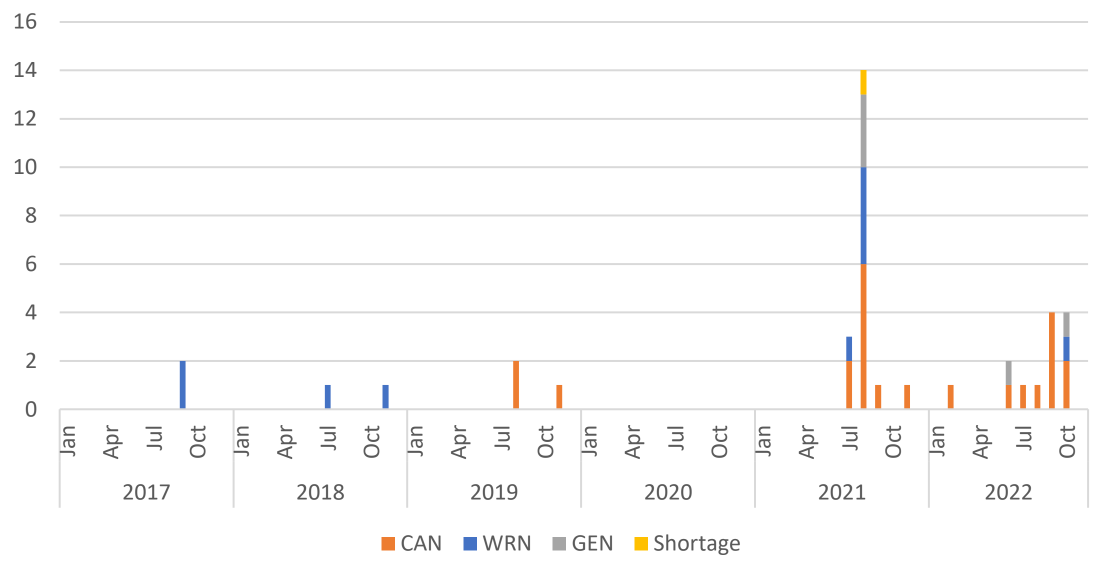
4.9. To this end, the system operator issues dispatch instructions to resource providers on how to vary their output/demand-response to balance the system and maintain a secure state in real-time. In formulating instructions, the system operator is required to choose the mix of resources that has the lowest total cost to maintain a secure system state. Importantly, the system operator can only dispatch resources that have previously been committed by operators to be available. Resources that are not committed are unable to make any contribution to system security.

4.10. If there is insufficient resource available to serve planned demand and maintain a secure state, then some forced demand curtailment or reserve shortfall will occur. The former will happen via system operator instructions if there is sufficient time, or automatic load shedding if not.

Recent experience with balancing supply and demand

4.11. There are signs that operational coordination issues are becoming more challenging. One indicator is the number of times the system had less than 200 MW of projected headroom in the supply stack (a so-called 'Low Residual Situation'). In these situations, there is little spare resource available to counter any unexpected wind generation reductions, higher demand, or other similar effects. Notices indicating these situations were introduced in May 2019 and their frequency has increased significantly in the last 18 months as shown in Figure 1.

Figure 1: Grid notices issued[12]



4.12. Another indicator is the number of times there is zero residual, and there is insufficient remaining resource offered to maintain standard reserve levels. This means the system does not have its 'normal' insurance reserve, and there is an increased risk of widespread load shedding being triggered if a contingency occurs when reserve is low.

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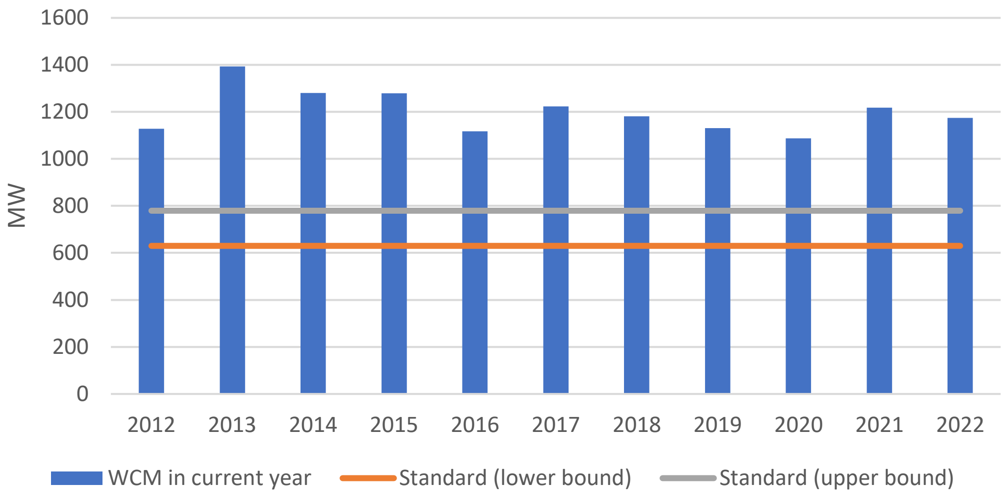
11 This is referred to as maintaining a secure system state.

12 "CAN" are advisory notices issued many hours ahead of real time indicating a potential supply shortage based on forward schedules. "WRN" are warning notices issued a small number of hours ahead of real time indicating an expected supply shortage. "GEN" are emergency notices advising of a supply shortage in real time. (this term is not used in the relevant para).

In these situations, the system operator issues ‘Grid Emergency Notices - Insufficient Generation Offers’. Such notices are expected to be issued only rarely, and again there has been an increase in frequency over recent years, with events recorded in 2021 and 2022 – the first since 2014.[13] In 2021 there were 2.25 hours of reserve or energy shortfall, and in 2022 there were 6 hours.

4.13. While the number of hours of reserve or energy shortfall in both years was below the level implied as an economic optimum and reflected in New Zealand’s capacity standard[14], it does raise some questions.

Figure 2 – North Island Winter Capacity Margin (WCM) in current year[15]



4.14. In particular, the increased frequency of tight supply is not because the margin between installed supply capacity and peak demand has tightened appreciably. On the contrary, Figure 2 shows that the North Island Winter Capacity Margin has remained well above 1,000 MW throughout the period covered by Figure 1. This indicates the proximate cause of tight balancing events has been operational coordination issues (such as unit commitment decisions) rather than investment adequacy. This in turn raises questions about why coordination is becoming more challenging, and whether there are underlying information and incentive gaps that need to be addressed.

System operator concerns

4.15. The system operator (Transpower) has also been expressing concerns about the outlook for winter 2024. In its Security of Supply Assessment (SOSA)[16] published in June 2022, the system operator suggested that that under certain scenarios the winter capacity margin could fall under the security standard set out in the Code as early as 2024.

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13 Grid Emergency Notices (GEN) occurred a handful of times a year between 2009 and 2014, but two market design changes helped to reduce their frequency. Firstly, scarcity pricing (introduced in mid-2013) set a floor on spot prices during periods of island-wide shortage. This was to better signal the value of energy during these periods. Secondly, the HVDC transmission charge allocation methodology was changed from 2017. Prior to this change, South Island generators were disincentivised from offering all available capacity unless a grid emergency notice had first been issued. In effect this meant an emergency notice could be issued even though there was sufficient supply physically available to maintain a secure system state (i.e. it could be a misleading indicator of physical conditions).

14 http://www.ea.govt.nz/assets/dms-assets/14/14134SSAD-2012-v0-6.pdf

15 The Transpower Annual Security Assessment calculates the WCM for a number of years ahead. This figure shows the 2017 ASA’s calculation of the 2017 WCM, the 2018 ASA’s calculation of the 2018 WCM, and so on.

16 https://www.transpower.co.nz/system-operator/planning-future/security-supply-annual-assessment

4.16. The system operator subsequently undertook further analysis and issued its Market insights report – winter review November 2022[17]. That report sets out system operator concerns that tight peak supply conditions may be more prevalent in winter 2023 than indicated in its June 2022 Security of Supply Assessment

Proximate causes of increased operational coordination challenges

4.17. Unit commitment issues were a contributing factor during each of the grid emergency events shown in Figure 1.[18] The need to make unit commitment decisions is not new. Nor are commitment decisions confined to slow-start thermal operators. Other resources also face commitment decisions, such as hydro operators that have storage well upstream of their power station, or electricity users with an ability to materially alter their demand with some notice. However, three recent factors may be making commitment decisions more challenging, especially for slower-start thermal generation. These factors are discussed below.

Higher fuel and carbon costs have raised start costs for thermal plant

4.18. The Rankine units and the combined cycle units at Huntly (Unit 5) and Stratford (TCC) account for around 20% of total system nameplate generation capacity and an even larger share of the controllable generation base.[19] Although relatively flexible if already hot, the Rankine units can take up to 12 hours to start from cold.[20] The TCC and Huntly 5 units can take a similar length of time or longer to start from cold. For each of these units a sizeable portion of their start costs is for fuel to heat boilers to bring units to a ready state.

4.19. The effect of higher start costs on commitment issues can be illustrated with a stylised example. Consider the operator of a hypothetical 200 MW slower-start thermal unit. For this example, we assume that this unit has fixed start-up costs of $40,000 and running cost of $150 /MWh. A forecast market schedule suggests a 95% probability of prices being $150 /MWh for the evening, but there is a 5% probability of higher prices if a cold weather front hits and raises demand in the evening.

4.20. In this example, spot prices in the high demand scenario would need to be above $1,483 /MWh for a risk neutral operator to commit the unit.[21] Now consider the effect if start costs are $75,000. In this case spot prices would need to be $2,650 /MWh for a risk neutral operator to commit the unit.[22] Alternatively, if spot prices in a high demand case were to remain at $1,483 /MWh, the expected likelihood of high demand conditions would need to increase from 5% to 9% to make commitment worthwhile.

4.21. Returning to the present context, fuel and carbon costs have increased substantially in recent years. One indicator is the cost of running a Rankine unit on coal, noting that such operation has been a major source of discretionary supply in recent years (and possibly for the next few years). Figure 3 shows the estimated short-run marginal costs for such

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[17] https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/bulk-upload/documents/Market%20insight%20report%20-%20Winter%20Review%20-%2011%20Nov%202022.pdf?VersionId=QaQVHc8zmQ6_FpC_Ux7GOimodObF9Vt2

[18] Data indicates there was at least one large slow-start thermal unit not committed to be available during each event.

[19] That is generation that can be ramped up or down and is not dependent on prevailing weather.

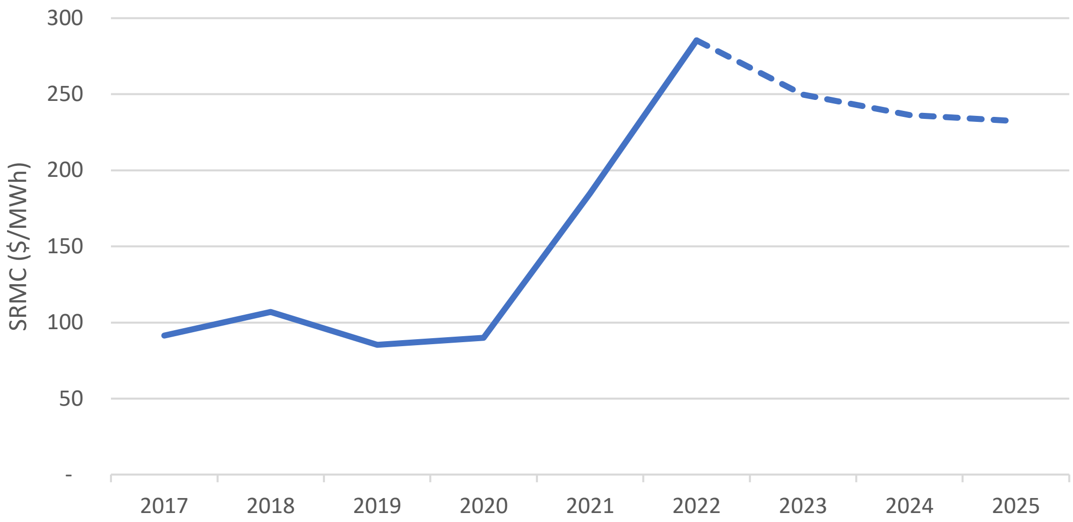
[20] These start times assume that plant is not offline for maintenance.

[21] This simplified example estimates the market price needed in the 5% of the time that the unit is dispatched and the prices are above SRMC to recover the losses incurred during other 95% of the time the unit is committed but prices do not rise above the unit SRMC. The example assumes a 3-hour period of peak demand.

[22] For simplicity this assumes running costs are unchanged with higher fuel costs. Allowing for this effect would raise the breakeven cost even further.

operations for recent years, and for the coming years based on forecast prices for coal and carbon. The chart shows the very substantial increase in these costs, especially in the last 18 months. It also indicates that costs are expected to remain high based on current information. Start-up costs are closely linked to fuel costs, meaning that start-up costs will probably have followed a similar trend in the past few years.

Figure 3: Rankine unit – estimated short run marginal costs running on coal



Rising intermittent generation make forecasts more uncertain

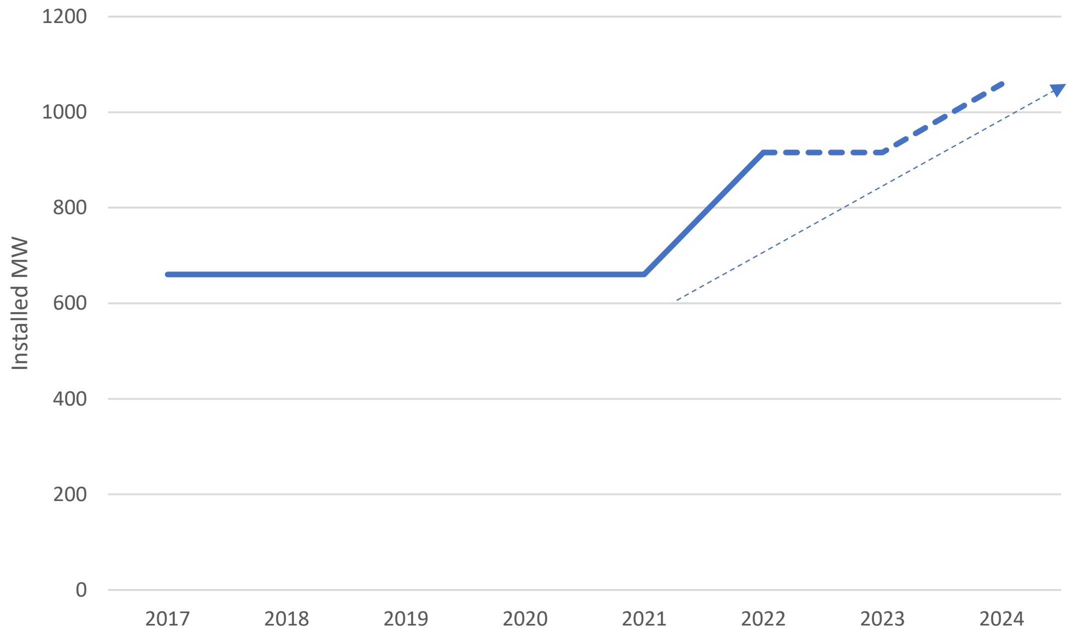
4.22. Commitment decisions are affected by the degree of uncertainty about forecast conditions. Returning to the illustrative example discussed above, a risk neutral operator should commit the unit if spot prices in the high demand case were above $1,483 /MWh and it believed there was a 5% likelihood of high demand conditions prevailing in real-time.

4.23. Now consider the situation where the operator has low confidence in the forecasts. If it believed (say) the demand forecasts tended to be biased upward and there was only a 2.5% likelihood of the unit being required, then expected spot prices would need to be $2,817 /MWh in that case to justify incurring the start costs. While higher uncertainty per se (rather than perceived bias) might not affect unit commitment choices for a risk neutral operator if the expected spot prices are high enough[23], it would make commitment less likely for operators who are loss averse, because it increases the likelihood that start-up costs will be incurred without corresponding revenues.

4.24. Returning to the present context, one of the most important inputs into forecasts is intermittent (primarily wind) generation levels. As discussed below, the Authority is currently examining options to improve wind generation forecasting accuracy. However, even if forecasting accuracy improves at the individual wind farm level, this is unlikely to offset the effect on forecasting accuracy from growth in the overall supply from intermittent generation. As shown by Figure 4 installed capacity has increased substantially since 2021 and is expected to grow further over coming years.

23 This would depend on the degree of asymmetry in spot price outcomes.

Figure 4 - Installed (and under construction) wind generation



4.25. We note also that dispatchable generation is not always reliable. If such generation is unexpectedly interrupted or fails to start that will also affect the accuracy of forecasts. For example, some thermal plant have recently experienced reliability issues[24].

Changing role of thermal generation means more frequent start decisions

4.26. The final key factor is the changing role of thermal generation. Historically it has provided a mix of baseload, hydro firming and short-term flexibility. The current portfolio of thermal plant on the system includes units with varying characteristics that are suited to these differing roles.

4.27. Thermal generation levels have recently begun to trend downward as rising carbon and fuel costs make it economic for renewables to replace higher capacity factor thermal generation. This means thermal generation is increasingly in a ‘reserve’ role (i.e. switched off) rather than being on (or at least warm) and capable of rapidly increasing output if required.

4.28. In very simple terms, the changing role of thermal means that slow-start units face an increasing number of commitment decisions, compared to earlier years. This raises the significance of commitment decisions from a system perspective.

Q1 Do you agree that operational coordination performance has become more challenging for the reasons indicated above? If not, what is your view and why?

[24] For example, a grid emergency was declared on 23 June 2022 when a 100MW gas fired peaking unit failed to start and a coal fired Rankine unit suffered a technical fault that reduced its output by approximately 140MW

Underlying cause: information and incentive gaps

4.29. From society's perspective the optimal outcome is that resources will be committed to be available where the expected benefits to consumers[25] exceed the associated costs.

4.30. The preceding sections describe some proximate factors that may be making unit commitment decisions more challenging. However, by themselves they do not mean commitment decisions would be sub-optimal.

4.31. To get sub-optimal outcomes one or more of the following must apply:

(a) participants lack information for sound decision-making. This includes commitment decisions by operators, and decisions by retailers and industrial users about whether they should obtain additional contract cover to reduce the likelihood of being exposed to high spot prices (noting these decisions may in turn affect a commitment action).

(b) participants do not face incentives to act in a way that reflects consumers' preferences (i.e. there is misalignment of private incentives and public interest).

4.32. Put simply, the problem is that the commercial viability of slow-start generation is changing, making managing system security harder with rising intermittent supply than it has been in the past. The question is what gaps exist in incentives and information that might be hindering the emergence of efficient generation and demand response solutions.

4.33. The following sections discuss the potential sources of information and incentive gaps.

Quality of information for decision-makers

4.34. Market participants need robust information on forecast system conditions to make commitment and short-term contracting decisions. They currently receive this type of information in forward schedules.

Forecast accuracy

4.35. Forecast accuracy is affected by underlying inputs, especially system demand and intermittent (primarily wind) generation levels.

4.36. On the demand front the system operator began using a new TESLA load forecasting service for conforming load in March 2022. Authority analysis of performance to August 2022 indicates the new tool has narrowed the spread of forecast error by 35% to 45%.[26] However, despite the improvement, there were still significant errors for forecasts in the period 8-16 hours ahead (a key period for commitment decisions). For most of this forecasting horizon there was a 90% probability that the forecast error would be between around -200 MW to +100 MW, while outliers extended to -600 and +700 MW.

4.37. There was only a gradual improvement in forecast accuracy until about four hours before real-time after which accuracy improves somewhat more quickly. The results also show a persistent negative bias of around 50 to 60 MW, i.e., forecasts tend to under-estimate demand on average, which is undesirable from a security perspective.

4.38. More generally, much of the recent improvement in demand forecasts has come from the application of machine learning techniques. In essence, these sift large volumes of data to identify patterns that can help predict the future. While very powerful, the technique takes time to 'learn' and this process can be harder in systems undergoing rapid change. In contrast to the stability of the 2010's, peak demand is now increasing much faster than

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25 Noting this will generally require a probability weighted assessment because a range of outcomes are possible.

26 See www.ea.govt.nz/assets/dms-assets/30/Accuracy-of-Wind-and-Load-Forecasts.pdf

average energy demand. For example, in the year to October 2022, the average of the top 20 peak demands was up 1.7% on the previous year (and 2.6% on a median basis). This compares to energy demand growth of around 0.2%.

4.39. Turning to intermittent generation, the Authority also looked at wind generation forecast accuracy at various intervals leading into real-time. Analysis of data for the year to March 2022 found a 90% probability that forecast errors would fall within a range from around -125 MW to +145 MW, while outliers extended as far as +/- 400 MW. Notably, it found a positive bias in forecast errors (i.e. forecasts exceeded actual levels). The analysis found no material improvement in forecast accuracy until the last 3½ hours before real-time, after which accuracy steadily improved and the positive bias disappeared. This analysis also found forecasting accuracy varied significantly among wind generators. This suggests appreciable scope to improve accuracy.

Usefulness of information

4.40. Another important point is that at present forward schedules provide only central estimates of forecast spot prices. Participants do not receive sensitivity cases to show the effect on prices if, for example, net demand[27] is higher or lower. This type of information is particularly relevant to commitment decisions when the system is tight and is provided in some other jurisdictions.

4.41. Participants can make some indirect inferences about possible price effects by examining how much 'headroom' there is in the supply stack. This information is included in forecast schedules in the form of 'residuals' which show the sum of all offered supply that is not scheduled for generation. However, this measure is only an approximate indicator and can at times present a false level of comfort. This is because the residuals indicator does not show the effect of transmission constraints or other factors that can reduce the real headroom on the system.

Potential for misaligned incentives

4.42. Putting information quality to one side, outcomes will not be optimal unless decision-makers have incentives to act in the wider public interest. The term 'incentive' is used in a broad sense and encompasses both incentives to increase returns from an action, as well as incentives to avoid a cost or penalty for non-performance. The following sections discuss areas where there could be a misalignment of incentives.

Under-signalling of shortage costs

4.43. If there is insufficient offered resource to maintain a secure state, the forecast schedules will indicate very high prices based on so-called scarcity values. These are intended to reflect the expected costs of lower reserve cover or projected demand curtailment and are set on a sliding scale depending on the forecast severity of the situation. Settlement prices are set using the same mechanism. This signalling approach was adopted with the introduction of real-time pricing on 1 November 2022.

4.44. Prior to this date a supply deficit in a forward schedule was indicated by 'infeasible prices' – i.e. these were default values set at very high levels. However, settlement prices were set using a different process. The move to real-time pricing should help with commitment decisions because forward schedules and settlement prices use the same approach with less need for guess work by participants. Having said that, the underlying scarcity price values were last fully reviewed in 2011. There is a question about whether they reflect current information, particularly given the increasing reliance on electricity as an energy source.

[27] Net demand here is used to refer to gross demand less uncontrollable generation. Thus, a reduction in uncontrollable wind output would increase net demand.

4.45. Putting that matter to one side for the moment, even if spot prices properly signal the expected cost and likelihood of demand curtailment, there is another factor that could cause misaligned incentives. Most electricity users purchase their power from a retailer on a variable volume contract. Forced demand curtailment will impose a cost on affected consumers, but the relevant retailer would not necessarily face a cost from scarcity prices being triggered.[28]

4.46. This is because demand curtailment will have both price and quantity effects for retailers. The triggering of scarcity prices will raise their purchase costs (all other things being equal), but the curtailment of demand is likely to lower retailers' spot energy purchase costs. The net impact will depend on each retailer's contract and spot purchase positions. It is even possible that a retailer could benefit from load shedding if it became a net seller in the spot market. The likelihood and extent of any such effects would be difficult to gauge and predict. Nonetheless, they could alter retailers' contracting incentives at the margin, and hence indirectly affect commitment decisions by operators.

4.47. A similar issue arises with any official public conservation campaign triggered in a prolonged energy shortage. In that event, the Code provides for retailers to make payments to their customers[29]. These payments are intended to proxy the cost of demand curtailment for consumers, and hence align retailers' incentives more closely with those of their customers. No such equivalent mechanism exists to better align retailer incentives with the interests of consumers in relation to short-duration involuntary demand curtailment.

4.48. Finally, there is a question of whether forced power cuts impose any costs that are broader than the foregone electricity consumption for affected consumers. For example, if forced demand curtailment were to reduce confidence in the power supply system, that could have wider flow-on effects. For example, it could hinder the uptake of electric vehicles and New Zealand's decarbonisation programme. The associated cost would be difficult to quantify but could be appreciable.

4.49. In summary, while the Code is designed to ensure that the likely cost to consumers of forced load shedding is reflected onto market participants, it is likely that this is not fully achieved in practice.

Lack of clarity around 'discretionary' demand curtailment volumes and use

4.50. Current arrangements rely on resource owners to determine the price at which they will make resources available, after taking account of the relevant costs they will bear.[30] A key exception is discretionary ripple control of hot water heating demand. Some of this demand-response capability is offered into the wholesale market in the form of interruptible load but the balance is not.

4.51. If a tight supply situation arises in real-time, the system operator will ask networks to reduce any discretionary demand, and most will respond by reducing any hot-water load not used for interruptible load.

4.52. This response can be significant in size[31] and have major impacts on prices in real time, but it does not appear in forecast prices. Further complicating matters, there is poor clarity on both the amount of resource available each trading period, and the price at which it is available. This creates a potential large mismatch between forecast and actual

[28] That will depend upon its contract position relative to its spot purchase volumes.

[29] Code Cl 9.19 – 9.28

[30] As discussed above, most consumers do not determine the value at which they will allow involuntary load shedding but scarcity pricing is intended to proxy this cost.

[31] Transpower estimated it was around 300 MW on 23 June 2022.

prices and will increase uncertainty for those making commitment and short-term contracting decisions.

4.53. An underlying issue may be poorly defined property rights for this demand-response, with consumers, networks and retailers having overlapping interests. The lack of clarity about the volume of resource available and its pricing also appear to be significant problems. Demand side market enhancements, such as Dispatch notification implemented as part of the real-time pricing project, is intended to address some of this market visibility issue.

Effect of market power

4.54. Operators' incentives to make resources available may be altered if they can exercise market power. For example, forecast spot prices might be sufficiently high to make it worthwhile to incur start costs, but an operator might nonetheless withhold the resource if this will increase their expected profit on sales from other already committed resources they own.

4.55. Competition is the preferred way to disincentivise such conduct, but when the system is tight competition is often limited. In these situations there will be greater reliance on the conduct rules in clause 13.5A of the Code. New rules were introduced in 2021. In brief, these require that when a generator or ancillary service agent makes an offer, these must be consistent with the offer that the party, acting rationally, would have made if no supplier could exercise significant market power.

4.56. The Authority reviewed the effectiveness of the new trading conduct rules and concluded they were having a positive effect on offer behaviour.[32]

Effect of risk and loss aversion on decision-making

4.57. Risk aversion refers to a tendency parties can have to prefer more certainty. Such parties are willing to pay some premium to reduce uncertainty, even though the premium exceeds the expected value of losses on a probabilistic basis. Loss aversion is a slightly different concept and refers to a tendency to value gains and losses differently, with a dollar paid out creating more pain than the pleasure received from a dollar gained.

4.58. If such biases exist among market participants, they could affect commitment outcomes. For example, risk or loss aversion could make operators less likely to make commitment decisions as they will incur costs with certainty, but they will obtain uncertain revenues. Similarly, loss or risk averse purchasers may be more likely to seek short-term contracts to lift their forward cover if forecast conditions indicate potential exposure to high costs.

4.59. Although we have not closely examined these issues, some participants have in the past emphasised the importance of their contract position on operational decisions.[33] This lends weight to the view that loss or risk aversion are relevant to commitment and contracting decisions.

4.60. Finally, the effect of any risk or loss aversion by the system operator is relevant. Some studies have suggested system operators tend to feel more pressure to keep the lights on, and less pressure to meet consumer preferences around system costs, particularly where these costs are hidden.[34] To the extent this is relevant, it may affect any areas where the system operator has discretion.

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32 See https://www.ea.govt.nz/assets/4-Monitoring/Information-paper-Post-implementation-review-of-the-trading-conduct-provisions.pdf

33 Commenting on the decision to not start an additional Rankine unit for use on 9 August 2021, Genesis Chief Executive reportedly said "Genesis calculated it could produce the electricity it needed to supply its own retail customers and meet the contracts it had entered into with other customers". See www.stuff.co.nz/business/126029919/power-cuts-genesis-boss-says-firm-feels-victimised-as-transpower-admits-error.

34 Arguably regulators or policy makers can be subject to similar pressures.

Transaction costs

4.61. Transaction costs are the costs of discovering information, negotiating contracts and enforcing them. Put simply, they are friction in the decision-making system and can mean that beneficial actions will not always occur.

4.62. Transaction costs are very relevant for operational coordination decisions. This is because commitment and associated contracting decisions often raise complex and uncertain issues, need to be made at short notice, and often occur outside normal business hours. Situations with high complexity and uncertainty mean parties often wish to spend more effort making sense of information and considering alternatives. This can include having interactions with other parties, such as potential demand response providers or suppliers, weather forecasters etc. Secondly, the narrow time window for making decisions means there is less time to explore alternatives and execute the preferred actions. For example, while a forecast weather-induced spike in demand tomorrow morning should (in theory) lead to increased contracting and commitment actions, real world frictions could make this impossible to achieve in practice.

4.63. The Authority's general preference is to find ways to lower transaction costs so participants themselves can more easily identify and execute mutually beneficial exchanges in a competitive market and in way that ultimately provides the most efficient reliability outcomes for consumers. The market schedules provided in the lead up to real-time are an example of this, because they gather information from multiple sources and present it a form to facilitate participant competitive negotiation and consequent decision-making.

4.64. Sometimes it is not possible to lower transaction costs and other solutions are required. For example, frequency keeping services are procured and managed by the system operator to finetune the balance between demand and supply. If there were no transaction costs, this service would arguably not be required as participants could trade instantaneously to balance themselves and hence the system as a whole.

Q2	**Do you agree that the factors in paragraphs 4.10 to 4.63 create information challenges or misaligned incentives, and that these make it hard to achieve optimal commitment actions? If not, what is your view and why?**

5. Options to better manage residual supply risk in winter 2023

5.1. Current arrangements seek to incentivise providers to make resources available when they are valued by consumers. This means consumers should get the level of operational reliability they are willing to pay for. This approach has worked well for many years.

5.2. However, as discussed in the preceding chapter, operational coordination performance has deteriorated in the last 15 months. This appears to be driven in part by various information and incentive gaps. The Authority considers it prudent to examine options to plug these information and incentive gaps before Winter 2023 if possible.

Q3 Do you agree that it is prudent to examine options to address information and incentive gaps identified above? If not, what is your view and why?

Proposed evaluation criteria

5.3. Our overarching objective is to ensure that any changes are in the long-term interests of consumers (i.e. for their long-term benefit, in terms of the Authority's statutory objective). With this factor in mind, we have evaluated options based on the extent to which they:

(a) Improve the information available to customers and operators to make efficient contracting and 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.

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

5.4. We have also considered the likely time required to implement each option based on current information.

Q4 Do you agree with the proposed evaluation criteria? If not, what is your view and why? Are there other criteria that the Authority should consider?

Options to better manage residual supply risk in winter 2023

5.5. Table 1 provides a summary of the options that have been identified to better manage residual supply risks for winter 2023. Each of the options is described further in the sections after the table. The list is not intended to be exhaustive and there may be other approaches that best provide for the long-term benefit to consumers. Feedback is welcome on any other options that the Authority could consider.

Q5 What if any other options should be considered to better manage residual supply risk for Winter 2023?

Table 1: Options to better manage residual supply risk for winter 2023

Option Label	Option	Improves information	Improve incentives	Risk of unintended harm	Readily modified /removed	Earliest date available	Proposed for further work
A	Provide better information headroom in supply stack	Y		Low	Y	By mid-2023	Y
B	Provide forecast spot prices under demand sensitivity cases	Y		Low	Y	By mid-2023	Y
C	Improve the accuracy of intermittent generation offers	Y		Low	N	By 2024	N
D	System operator review of wind offers based on external forecast	Y		Low	Y	By mid-2023	Y
E	Clarify availability and use of 'discretionary demand' control (such as ripple control)	Y		Low	Y	By mid-2023	Y
F	Introduce new integrated ancillary service to offset increased uncertainty in net demand[35]		Possibly	Moderate	N	By mid-2023?	Y
G	Selectively increase existing ancillary service cover at times to offset increased uncertainty in net demand		Possibly	Moderate	Y	By mid-2023	Y
H	Require retailers to make compensation payments to customers affected by forced power cuts		Y	Low / Moderate	N	By 2024	N
I	Review administered prices to apply in energy or reserve shortages		Y	Low / moderate	N	By 2024	N
J	Introduce hours-ahead market	Y	Y	Moderate	N	By 2025/26	N
K	Procure additional resource outside of spot market			High	N	-	N

[35] Demand less intermittent generation supply.

A – Provide better information on headroom in supply stack

5.6. Participants need timely and sound information to make their commitment and short-term contracting decisions. A key weakness with current information is that forecast schedules provide limited information on the headroom in the supply stack.

5.7. The main headroom indicator that is currently published is the 'standby residual check' measure that indicates:

(a) Whether the total offered supply is sufficient to replace the energy lost following the tripping of the single largest risk plant and still maintain ancillary service requirements (the 'energy residual'); and

(b) Whether there are sufficient scheduled reserves to cover the next risk plant (the 'capacity residual').

5.8. This is a complex and conservative calculation that yields potential shortfall notices that have no operational impact.

5.9. A separate anonymised offer stack is available via WITS that provides forecasts of the energy offer stack for each trading period. However, this information is not adjusted for any energy that has been dispatched for instantaneous reserves or is subject to a constraint – either transmission or frequency keeping provision. This leads to an overly optimistic view of the available supply which adds further uncertainty to the unit commitment process.

5.10. To further complicate the picture, the system operator issues their Warning and Grid Emergency Notices based on shortfalls of energy offers after taking into account constraints and cleared reserve offers. The underlying headroom information behind these calculations is not available to participants so it cannot be considered in unit commitment decisions.

5.11. To provide better information to participants, the residual offer information used by the system operator could be published to the market with the forecast market schedules. Presentation options for this information are being investigated with the system operator. Current options are to present the information via the existing standby residual check displays on the WITS interface or a dedicated page on the system operator web site. The former option is probably preferred because participants typically find it easier if all information is on one system. We understand that this option would not require a change to the Code nor a change to the system operator Policy Statement but some software development by both the system operator and NZX. It would need to be confirmed that these software changes could be implemented in time for Winter 2023.

Q6 Do you think it would be beneficial to publish the residual offer information used by the system operator when calculating Grid Warning and Emergency Notices? If not, what is your view and why?

B – Provide forecast spot prices under demand sensitivity cases

5.12. At present forward schedules provide only central price forecasts. Parties making commitment and short-term contract decisions need to assess the range of possible future outcomes, not only the central outcome.

5.13. To address this need, price sensitivity forecasts could be published that show the effects if net demand[36] is higher or lower by a predefined amount. Price sensitivity information should 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 would still be provided).

5.14. Information of this type was provided by Transpower in 2020 on a trial basis but was discontinued. We understand there was limited interest in the sensitivity information at that time (possibly the effect of Covid lockdowns did not help) but we expect it would be much more useful to participants going forward.

5.15. Ideally the information would be made available via WITS. However, given the short development timeframe to be available by Winter 2023, this may not be possible. If that is the case, the information could be made available via another channel such as the system operator's website (this is how the information was provided in the earlier trial). This would mean it is available on a reasonable endeavours basis and would not have the same level of assurance and technology resilience as via WITS. Nonetheless, provision of this information could be useful for participants in their commitment and contracting decisions.

5.16. This option is one that could possibly be progressed without Code amendment.

Q7	**Do you think it would be beneficial to provide sensitivity case spot price forecasts in forward schedules, as well as central forecasts? If not, what is your view and why?**

C – Improve the accuracy of intermittent generation offers

5.17. As discussed previously, intermittent generation levels are already a significant source of uncertainty and there is variation among wind generators in their forecast accuracy.

5.18. The share of supply from intermittent sources is expected to grow significantly over time. It is therefore very important to improve intermittent generation forecasts. This should include the type of information that will be most useful for coordinating the system (such as sensitivity cases as well as P50 forecasts).

5.19. The Authority has initiated work on improving intermittent generation forecasts/offers and expects to have proposals ready for consultation in 2023. Any Code changes which might flow from this work would be likely to have cross-industry operational impacts from 2024.

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36 This is defined as forecast demand minus forecast uncontrolled generation.

Q8 Do you agree that cross-industry work on improving the quality of intermittent generation forecasts is unlikely to be available for Winter 2023? If not, what is your view and why?

D – System operator review of wind offers based on external forecast

5.20. An interim option to improve the accuracy of wind offers is for the system operator to procure wind forecasts and compare it to offers supplied by wind farm operators. If there were any significant differences, then the system operator could advise this to the market and relevant parties. The wind operators would remain entirely responsible for their offers, but the additional information could aid in their decision-making.

5.21. The system operator trialled a similar process in winter 2022. It advises that during the week beginning 12 August 2022, a 300 MW difference was identified between offers and wind forecasts. This information was shared with stakeholders leading to a convergence between wind offers and forecasts. That in turn indicated an energy shortfall and additional thermal generation was offered to close the gap. This option has an estimated of cost $150k for winter 2023 and would require approximately one month lead-time.

Q9 Do you agree that the system operator should procure an external wind forecast and ask participants to review their offers if there are large discrepancies between the forecast and offers? If not, what is your view and why?

E – Clarify availability and use of discretionary demand control

5.22. 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 will call upon network companies to reduce demand. 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 thermal unit commitment decisions.

5.23. At present this discretionary demand is mainly in the form of hot water heating load that is not already used for interruptible load. In future, other sources of discretionary demand could include any flexible charging of electric vehicles.

5.24. The volume of such resource and its treatment in forward schedules and real-time can have major implications for commitment and contracting decisions. It is important to get much better information on these resources, and clarity on when they could be used.

5.25. One possible option would be for participants controlling this resource to reveal it to the market via the ‘Dispatch Notification’ product to be introduced in April 2023. However, it is not clear whether participants concerned would have incentives to do this – particularly in the case of distributors who do not participate in the spot market. Ideally, distributors would be incentivised to offer demand management contracts to retailers to manage their customer load on their behalf. However, it’s not likely that many, if any, distributors currently can discriminate the control their hot water ripple control systems to this degree.

Technology is becoming available that would make this possible[37] but its widespread use may be some time away. To address this in the short term, the Code could require distributors to utilise the Dispatch Notification product when forward schedules indicate the system is becoming tight (e.g. when the system operator releases a Low Residual CAN).

5.26. This would provide greater visibility on the expected size of this resource in forward schedules, which could assist participants with short-term contracting and commitment decisions. However, there would also be a need to better clarify the conditions when this resource would be called upon by the system operator. This change could require Code changes but appears to be feasible for implementation prior to winter 2023.

Q10 Do you agree that the availability and use of 'discretionary' demand control (such as ripple control not used for instantaneous reserves) should be clarified? If not, what is your view and why?

F - Introduce a new integrated ancillary service

5.27. Purchasers in the spot market pay suppliers for energy that is actually produced and consumed and there are no payments for availability per se.

5.28. While this is true for provision of active energy, availability payments are made to providers of the following ancillary services:[38]

(a) Instantaneous reserve – to avoid the cascade failure that could otherwise occur before new resources could be dispatched, the market pre-procures reserve (generation or demand response) to quickly counter a sudden supply loss. The amount of cover varies by trading period to match the size of the largest risk.

(b) Frequency keeping – to address fluctuations in controllable supply needed between successive dispatch instructions caused by variations in demand, wind generation etc, some frequency-keeping providers are designated each trading period to move their generation up or down to fine tune the system balance. The amount of service is currently set at +/- 15 MW in the North Island and +/- 15 MW in the South Island under normal conditions.

5.29. While availability payments apply, procurement of these services is closely integrated with the energy spot market. For example, some resources can provide active energy or instantaneous reserve. Relevant parties can offer both types of capability and the market clearing engine will utilise the resources to minimise overall system costs. Efficiency is also fostered by allocating procurement costs to causers where practical. For example, the 'causers' of the need for instantaneous reserve are large supply assets (generators and the HVDC) and these parties pay availability and event charges.

5.30. The suite of current ancillary services reflects the historical needs of the New Zealand system. As noted earlier, the system's needs are changing as the share of intermittent renewable generation increases. In particular, there may be a case for a new ancillary

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[37] Influx metering recently announced the addition of retailer addressable hot water control to their meters: https://www.influxdata.nz/solutions/influx-demand-management-for-hot-water

[38] Active energy is the term used in the Code for energy procured in the ½ hourly spot energy market. Ancillary service providers can also receive payments based on actual services provided (as well as availability).

service product to provide a buffer against unexpectedly large variations in demand or intermittent generation going forward as these risks increase in size.

5.31. Reserves of this type exist in some other markets are typically referred to as 'standby-reserve'. Such reserve could be provided by demand response, or flexible generation or batteries. The amount of stand-by reserve could be varied to reflect system conditions (as occurs with some current ancillary services).

5.32. A risk with this option is that unless it is integrated with the rest of the spot market, it will not be reflected in spot prices and could distort incentives. For example, if it is not integrated, there is potential for resource providers to simply swap from participating in the spot market to offering the ancillary service (if the latter is more remunerative). That could result in no net improvement in reliability but higher procurement costs to consumers. There are also risks that, longer term, a new ancillary service may act as an effective subsidy for unproductive or expensive plant, and stifle investment in more efficient generation or demand management solutions.

5.33. To mitigate this type of risk and to incentivise efficient decisions, arrangements should be neutral between demand- and supply-side solutions, and co-optimised with the energy spot market wherever feasible (as with the current ancillary services). In addition, costs should be allocated to causers as far as practical. Introducing a new ancillary service is expected to require Code amendments and changes to software. Potential providers would also need time to consider eligibility requirements and qualify their resources.

5.34. The system operator has indicated that it may be possible to implement a new integrated ancillary service in time for winter 2023 if preparatory work were to occur from late 2022.

Q11 Do you agree that work should be undertaken on a new integrated ancillary service for winter 2023 to help manage increased uncertainty in net demand? If not, what is your view and why?

G - Selectively increase existing ancillary service cover

5.35. As an alternative to introducing a new ancillary service, it could be possible to lift the volume of an existing ancillary service cover margin. Doing this on a selective basis could provide a stronger market signal for the need for additional reserve at times when the system is tight and there is increased uncertainty in demand and intermittent generation output.

5.36. Both the instantaneous reserve and frequency keeping ancillary services effectively require some resources to be diverted from the energy market into ancillary service provision, and therefore increasing the procurement volume of these services would increase the total volume of supply required. However, either service would have subtly different effects including which parties pay for the service and which parties can participate as providers.

5.37. The advantages of using an existing ancillary service to address coordination risk are that:

(a) It is more likely it could be introduced before winter 2023.

(b) It would be neutral as between providers of additional resource in either the instantaneous reserve or frequency keeping markets and between supply-side and demand-side in the instantaneous reserve market. This is desirable to maintain competition and minimise economic costs.

(c) It should not undermine investment and contracting incentives, unlike any options which make supplementary payments to suppliers that are completely outside of the spot market.

5.38. A risk identified with this option is that resource providers might try to artificially trigger it by withholding resource that would otherwise have been made available in the energy spot market. The Authority would seek to address this by closely monitoring behaviour in the lead up to, and duration of, any instances where the increased ancillary service requirement is triggered. In this context, it is important to recall that both generators and ancillary service agents are covered by the trading conduct rules in Part 13.5A of the Code.

5.39. The Authority envisages that the system operator would be the party to determine when the trigger for additional ancillary service volume occurs. We expect that this trigger would be based on a forecast shortage in the system operator's existing forward schedules. The trigger may take a similar form to the process by which low residual CANs are currently produced from forward schedules.[39] However, unlike CANs, the conditions for the trigger would need to be more strictly defined with limited discretion by the system operator.

5.40. It is not possible to precisely forecast the impact of this measure on economic costs or spot prices. However, increasing the ancillary service requirement at times would be expected to increase the amount of resource offered to the market.[40] That in turn implies an increase in operating costs for suppliers (and would likely lead to somewhat higher spot prices when activated). However, increased available supply on the system should reduce the chance of shortage, which is beneficial for consumers.

5.41. A key part of designing a new ancillary service would be to ensure that the expected benefits exceed (or at least equal) the increase in costs.

5.42. The Authority expects if additional ancillary services were procured at times, these would be relatively limited each year. Accordingly, each time the system operator triggered procurement via a notice, it would provide a report outlining both the conditions that led to the issuance of the notice as well as what occurred during the period of low forecast residual supply.

5.43. A key difference between using higher frequency keeping or instantaneous reserves is which parties pay for the increased procurement volume:

(a) Frequency keeping costs are currently recovered entirely from purchasers according to the quantity of electricity purchased. While demand fluctuations have historically been the major driver of the need for frequency keeping, variation in intermittent generation output has now also become a significant driver. There appear to be reasonable grounds to revisit the allocation of frequency keeping costs. However, it is unclear whether that is practical before winter 2023.

(b) Instantaneous reserve costs are recovered from parties according to their contribution to the need for instantaneous reserve. This is currently confined to operators of larger generation units and the HVDC link. As with frequency keeping, there appear to be reasonable grounds to alter the cost recovery provisions if additional reserve were procured to address increase net demand uncertainty. However, again, it is unclear whether that is practical before winter 2023.

5.44. Choosing either ancillary service may alter which parties can participate directly as resource providers. Currently there are no demand side participants in the frequency

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[39] 1.1 Low residual demand CANs themselves would not be a good candidate to function as the trigger because these CANs already serve a purpose to signal to the market to increase supply if possible. Any trigger would have to occur after parties have revised offers in response to the CAN.

[40] If it did not happen the process would not be functioning as intended.

keeping market, although they are not specifically excluded to under the Code. It appears unlikely that demand side participants would be ready to take part in the frequency keeping market by winter 2023.

5.45. Any increase in procurement of an existing ancillary service would be intended as an interim measure until longer-term solutions (such as a new ancillary service) could be introduced. For this reason, if this measure was adopted, it should be time limited, unless it was extended by a formal Code amendment process.

5.46. This option would likely require changes to the Code (to alter the use of ancillary services and the cost allocation) and possibly a change to the system operator procurement plan.

Q12 Do you agree that selectively increasing ancillary service cover should be considered as an interim option for Winter 2023? If not, what is your view and why?

Q13 If increased cover from an existing ancillary service at times is pursued further as an option for Winter 2023, what are your views on whether to utilise frequency keeping or instantaneous reserve, and why?

H – Require retailers to make compensation payments to customers affected by forced power cuts

5.47. If consumers experience forced power cuts due to insufficient generation, that will reduce retailers' spot market purchase costs, all other things being equal. This creates a potential misalignment between retailers' incentives and the interests of their customers. Ideally consumers and retailers would explicitly address this issue in their supply contracts. For example, some customers might be more willing to tolerate the risk of supply interruption in return for a lower headline tariff, whereas others might prefer to be paid for a right to interrupt.[41] However, as far as we are aware at present, retail supply contracts do not explicitly address the issue of compensation for power cuts due to insufficient available generation.

5.48. A similar misalignment issue arises with any official public conservation campaign triggered in a prolonged energy shortage. Such campaigns would lower the purchase cost for retailers, with the cost being borne by consumers. In that event, the Code provides for retailers to make payments to their customers intended to proxy the cost of demand reduction for consumers. A similar mechanism could be introduced to cover shorter-duration power cuts caused by insufficient supply resources being available.

5.49. This mechanism would define the default level of compensation payable to consumers but would also allow them to mutually agree a different approach. The level of compensation and triggers would require careful design to ensure it achieves the intended effect. The Authority would also need to be mindful of current access disruptions in the ASX futures market and the effect on the availability of suitable hedging products. This option would require amendments to the Code.

[41] Ideally, any forced demand curtailments would take account of the relative preferences of consumers to be interrupted. In practice, forced load shedding is still quite a blunt instrument but technology is making it easier to more selectively target among different customers.

5.50. Based on current information it appears unlikely this option could be in place before Winter 2023, but nonetheless stakeholder feedback on the merits of such an approach to protect the long-term interests of consumers is welcome.

Q14 Do you agree the option of requiring retailers to make compensation payments to customers affected by forced power cuts should not be explored for Winter 2023? If not, what is your view and why?

I - Review administered prices to apply in energy or reserve shortages

5.51. Parties' incentive to take action to avoid shortages will be strongly influenced by spot prices in those events. Ideally those prices would be set by consumers who indicate the price at which they will forego usage (and/or sell purchased power back into the system). While this can occur to some extent with current arrangements, if forced curtailment is required spot prices will be based on administratively determined values. These values were 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).

5.52. The values were last fully examined in 2011 although the way they apply was reviewed more recently as part of the introduction of real-time pricing. The values could be re-examined to ensure they are appropriate going forward. This option would require significant analysis and consultation before changes to the Code could be made and appears impractical before Winter 2023.

Q15 Do you agree that reviewing the default pricing in the Code to apply in energy and reserve shortfalls should not be explored for Winter 2023? If not, what is your view and why?

J – Introduce hours-ahead market

5.53. No matter how good forecasts become there will be some uncertainty about how conditions will actually turn out in real-time. This uncertainty can present significant challenges for participants that have significant risk or loss aversion.

5.54. A tool used in some other countries to address this is an hours-ahead market. In simple terms, an hours-ahead market creates a two-stage settlement process. All parties would be required to submit offers/bids for their generation/demand (say) eight hours ahead of real-time. The first set of binding financial commitments would be formed based on these hours-ahead market offers/bids.

5.55. Parties whose actual demand or generation deviated from their cleared ahead-market quantities would settle those differences based on prices calculated in the real-time spot market (which effectively becomes a balancing market). This is the second stage of the settlement process.

5.56. The effect of these arrangements is to give buyers and sellers price certainty, provided they act in accordance with the level of demand/generation contracted in the hours-ahead market. However, if they deviate from the hours-ahead market commitments, they no longer have price certainty because mismatches are settled at the balancing price, which is not known until real-time.

5.57. An hours-ahead market could be useful to parties for whom price certainty ahead of real-time is very important. For example, in the future there are likely to be significant volumes of batteries on the system. Battery operators or battery aggregators could find an hours-ahead market helpful to schedule their charging and discharging decisions over the next (say) 8 hours. Similarly, demand response providers who need to plan ahead could benefit from the price certainty provided by an hours-ahead market.

5.58. 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).

5.59. Additionally, an hours-ahead market only provides security in so far as the resources scheduled are able to start and run when needed. As previously discussed, one of the issues impacting operational coordination is the reliability of the current fleet of thermal generation.

5.60. Having said this, to the extent that hours-ahead markets improve coordination, they should help to reduce price volatility in both ahead and balancing prices.

5.61. Introducing an hours-ahead market would take significant time to introduce because of the changes needed to market systems. There could also be transitional issues to address, such as the effect on existing hedge contracts (e.g. whether they settle against ahead or balancing prices). This option would require significant policy development and market systems changes. It would also significantly impact participant processes and practices. It is not feasible before Winter 2023.

Q16 Do you agree that an hours-ahead market should not be explored for possible adoption for Winter 2023? If not, what is your view and why?

K - Procure additional resource outside of the spot market

5.62. Separate payments outside of the spot market could be used to encourage providers to make more resource available. For example, the system operator could contract with resource providers[42] to make additional resource available at times, such as when there is (say) less than 200MW of headroom in the supply stack.

5.63. The contracts would allow the system operator to call for resource to be made available in return for a predefined contract payment. Costs could be recovered by a levy across all wholesale purchasers or some similar approach.

5.64. A concern with this type of mechanism is that it can undermine spot market incentives for parties to commit resources. This arises because the mechanism allows resource providers to choose between making resources available solely via the spot market or keep them out of the spot market in the hope this will trigger the separate 'top-up'

[42] In some jurisdictions this type of option is referred to as a 'warming contract' because payments are normally made to slower start thermal plant to get warm or stay warm. However, such payments could be made to other types of resource providers.

mechanism. Providers are likely to prefer the latter if given a choice because it would offer a higher reward (otherwise there is no increase above the normal level of resources).

5.65. The mechanism would likely also undermine incentives for purchasers to enter into short term contracts with resource providers (and therefore reduce the likelihood of contracts incentivising resource availability). This is because the additional resource procured via separate payment mechanism would lower expected spot prices. That will reduce the incentive on purchasers to self-insure via contracts.[43]

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

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

5.68. Overall, we consider this option has significant risks and propose that effort would be better directed towards other options.

Q17 Do you agree that mechanisms that procure additional resources outside of the spot market should not be explored further for Winter 2023? If not, what is your view and why?

Current overall assessment of options

5.69. Our current overall assessment of the options is set out below.

Options A, B, D, E would improve information and appear attractive

5.70. Options A, B, D, E appear likely to improve the information available for short-term contracting and operational decisions and have a low risk of unintended harm. All appear feasible for implementation ahead of Winter 2023 and could be readily modified/removed if needed.

5.71. Based on the above factors, and subject to feedback from stakeholders in this consultation process, Options A, B, D and E are strong candidates for further detailed work.

Q18 Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?

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[43] An alternative way to think about it is that some insurance is procured centrally by the system operator, reducing the need for purchasers to self-insure.

Options F-G to address incentive gaps require more assessment

5.72. Options F-G both seek to use an ancillary service to address potential incentive gaps associated with rising uncertainty about peak demand and supply intermittency. These options could provide more assurance of reducing residual supply risk, but also have greater likelihood of raising supply costs paid by consumers. It is important to consider whether the benefits of the former would outweigh the costs of the latter effect. Further analysis will be required to form a clearer view on that issue. Nonetheless, it is useful to obtain stakeholder views at this point as an input to further consideration and analysis.

Q19 Do you agree that options F and G should be assessed further to determine if they are likely to have net benefits? If not, why not?

Options C, H-K are currently not attractive due to timing or other factors

5.73. Options C, H-J appear attractive in principle but would not be available for winter 2023. Work on option C is progressing as a discrete project and making urgent changes ahead of Winter 2023 risks undermining the long-term benefits of the project.

5.74. Options H and I would require significant effort and have the potential to produce unintended consequences if not developed carefully. The Authority considers it imprudent to attempt to fast track this work ahead of Winter 2023.

5.75. Option J relates to the issues being considered by MDAG in its 100% renewables stream. The integration of an hours ahead market would require a significant redesign of the wholesale market and would likely have flow-on effects on other aspects of the broader wholesale market e.g. the pricing and settlement of both ASX and OTC hedges. Given the need for careful design and significant changes to the wholesale market systems and operation, the Authority is not recommending progressing with this option for Winter 2023 but will continue to support the MDAG work.

5.76. Option K is not considered to be attractive due to the risk of unintended consequences and likely difficulty in modifying or removing it. Given these factors, the Authority does not propose to undertake further work on Options C and H-K in advance of Winter 2023.

Q20 Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?

Other matters relevant to consideration of options for Winter 2023

5.77. The Authority is interested in submitters' views on whether there are any other matters that should be considered when assessing options to better manage residual supply risk for Winter 2023.

Q21 What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?

6. Next Steps

6.1. This consultation paper sets out a range of potential options to better manage residual supply risk for Winter 2023.

6.2. The Authority has sought to describe the options in sufficient detail to allow stakeholders to provide meaningful feedback. The Authority recognises stakeholders might prefer to see more detail for some options. However, that would have meant delaying the release of this paper until early 2023. That in turn would risk not optimising the opportunity for feedback to influence the shape of any options adopted before Winter 2023.

6.3 Consideration of feedback on this paper, the Authority will refine any options that it would seek to progress for implementation before Winter 2023. It will also engage with the system operator and NZX (and possibly other parties) to better understand potential implementation issues associated with potential options.

6.4 If the Authority decides to progress any option that would require a Code amendment, it will endeavour to consult further with stakeholders if it is practical to do so. However, it is possible that the timelines may make that impractical. If there is insufficient time to allow for consultation on a specific Code amendment and the relevant statutory requirements were satisfied, the Authority may need to consider making an urgent Code amendment under section 40 of the Electricity Industry Act.

Appendix A Format for submissions

Submitter	

Question	Comment
Q1. Do you agree that operational coordination performance has become more challenging for the reasons indicated above? If not, what is your view and why?	
Q2. Do you agree that the factors in paragraphs 4.10 to 4.63 create information challenges or misaligned incentives, and that these make it hard to achieve optimal commitment actions? If not, what is your view and why?	
Q3. Do you agree that it is prudent to examine options to address information and incentive gaps identified above? If not, what is your view and why?	
Q4. Do you agree with the proposed evaluation criteria? If not, what is your view and why? Are there other criteria that the Authority should consider?	
Q5. What if any other options should be considered to better manage residual supply risk for Winter 2023?	
Q6. Do you think it would be beneficial to publish the residual offer information used by the system operator when calculating Grid Warning and Emergency Notices? If not, what is your view and why?	
Q7. Do you think it would be beneficial to provide sensitivity case spot price forecasts in forward schedules, as well as central forecasts? If not, what is your view and why?	
Q8. Do you agree that cross-industry work on improving the quality of intermittent generation forecasts is unlikely to be available for Winter 2023? If not, what is your view and why?	
Q9. Do you agree that the system operator should procure an external wind forecast and ask participants to review their offers if there are large discrepancies between the forecast and offers? If not, what is your view and why?	
Q10. Do you agree that the availability and use of ‘discretionary’ demand control (such as ripple control not used for instantaneous reserves) should be clarified? If not, what is your view and why?	
Q11. Do you agree that work should be undertaken on a new integrated ancillary service for winter 2023 to help manage increased uncertainty in net demand? If not, what is your view and why?	
Q12. Do you agree that selectively increasing ancillary service cover should be considered as an interim option for Winter 2023? If not, what is your view and why?	

Q13. If increased cover from an existing ancillary service at times is pursued further as an option for Winter 2023, what are your views on whether to utilise frequency keeping or instantaneous reserve, and why?	
Q14 Do you agree the option of requiring retailers to make compensation payments to customers affected by forced power cuts should not be explored for Winter 2023? If not, what is your view and why?	
Q15 Do you agree that reviewing the default pricing in the Code to apply in energy and reserve shortfalls should not be explored for Winter 2023? If not, what is your view and why?	
Q16 Do you agree that an hours-ahead market should not be explored for possible adoption for Winter 2023? If not, what is your view and why?	
Q17 Do you agree that mechanisms that procure additional resources outside of the spot market should not be explored further for Winter 2023? If not, what is your view and why?	
Q18 Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?	
Q19 Do you agree that options F and G should be assessed further to determine if they are likely to have net benefits? If not, why not?	
Q20 Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?	
Q21 What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?	

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code