16 December 2022

Electricity Authority
By email: WholesaleConsultation@ea.govt.nz

Driving efficient solutions to promote consumer interests through winter 2023

Meridian appreciates the opportunity to comment on the Electricity Authority's consultation paper on potential options to better manage risks to the balancing of supply and demand for winter 2023.

Public expectations of reliable supply

The Authority begins the consultation paper with a discussion of what constitutes an ideal level of reliability. The paper refers to the security of supply standards set out in clause 7.3(2) of the Code to support the assertion that consumers would not want 100% reliability because of the associated costs to gold plate the power system. The example given of duplicate low voltage distribution lines seems to conflate the public appetite for:

- localised interruptions to service; and
- nation-wide reliability issues due to insufficient generation.

In Meridian's opinion, the Authority should be clear that the risk it seeks to address in the consultation paper is about national reliability and generation resource adequacy. We consider it likely that the public and political appetite for nation-wide reliability and generation resource adequacy issues is very close to zero.

The security of supply standards in the Code do not assume 100% reliability. However, those standards have not been reviewed since 2017 despite the Authority finding at that time that "some changes to the security of supply standards may be warranted" and that, while it decided not to make that changes at that time, a further review should be undertaken "sooner than the regular five-yearly period".[1] To our knowledge there has been no such review subsequent to 2017. It may be timely to undertake this work both to:

- test whether the costs and benefits implied by the current standards are still reasonable; and
- test whether additional standards might be useful if the current North Island Winter Capacity Margin has not been a reliable indicator of the recent peak resource adequacy risks.

There may be an opportunity to simultaneously review (and codify if appropriate) the system operator's New Zealand Generation Balance application and the concept of the 200MW residual that the system operator uses to meet its principal performance obligations. Meridian would support an open review of all these standards and tools to increase clarity and the confidence of the industry as a whole that prudent processes are in place.

We do however agree with the Authority that the security of supply standards are a monitoring tool only and that the actual level of security of supply is determined by the actions of wholesale market participants.

The emerging winter peak problem

Meridian agrees that there are some recent signs that operational coordination is becoming more challenging with potential adverse implications for reliability, particularly during winter peak demand periods.

Meridian broadly agrees with the way the Authority has framed the risks for winter 2023 and that there may be underlying information and incentive gaps. In our opinion there three distinct underlying issues:

1. There can be periods at peak times when there are insufficient resources (flexible generation and demand response) to respond to peak periods;
2. Some resources may not be available when needed (in particular because thermal generation is less commonly running as baseload generation and it can be challenging for the owners of older, slow-start thermal generation to make an increasing number

[1] https://www.ea.govt.nz/development/work-programme/risk-management/winter-energy-and-capacity-margins-review-20172018/development/

of commitment decisions in advance when the profitability of generating is uncertain over the time horizon needed to make the commitment decision); and

3. Some resources may not be clearly visible to the system operator (meaning the extent of any shortfall risk is unclear).

The Authority may find the assessment of options simpler if it first determines the relative significance of each of these underlying problems. For the time being we will assume that each of these underlying problems equally contributes to the winter peak resource adequacy issue and therefore that options to address all of these underlying problems may have merit.

As the Authority notes, winter peak issues have been exacerbated recently by:

- increased uncertainty around peak demand;
- higher impact of un-forecast intermittency with over 1GW of wind generation now installed (and variable quality wind forecasting); and
- higher warm-up and idling costs for slow-start thermal units (fuel and carbon costs are higher).

In Meridian's opinion, the Authority's description of the risk and underlying causes is lacking in several respects. Firstly, while improved information can help to provide increased certainty for commitment decisions ahead of real time, the future will always have a degree of uncertainty. Rather than focusing on improving the quality of forecasting information, the Authority could also consider whether additional elements of market design could help to overcome some of the inherent uncertainty for commitment decisions or otherwise improve reliability.

Secondly, it is worth acknowledging that the increased uncertainty around peak demand has been exacerbated by changes in the incentives and use of ripple control as well as increased decarbonisation activity through fuel switching, particularly for industrial process heat and residential heating.

Finally, while the Authority acknowledges that the wider problem is that "investment in new flexible generation and demand response solutions are needed", the Authority could more directly acknowledge in this paper (consistent with the recent material on the review of competition in the wholesale market) that a key driver of peak capacity shortage is likely to be government policy, in particular:

- The NZ Battery Project – direct investment in peak and dry year capacity (or the threat thereof) is likely to have had a chilling effect on private investment in peak capacity and demand response solutions over the past few years. Investors may struggle to make a business case if there is a real risk that the Government intends to deliver a large scale solution to manage winter peak capacity during this decade (even though the need for increased peak capacity seems to have arisen far in advance of the timeframes the Government is contemplating for a large scale investment).

- Uncertainty about the Government's intentions to phase out the use of fossil gas for electricity generation in order to deliver on its 100% renewable electricity generation aspirations. Gas peaker options such as Todd Generation's Waikato Power Plant at Otorohanga have been consented but not built. Meridian can only speculate on the reasons, but Concept's August 2021 review of the generation environment carried out for the Authority noted it is "likely to be affected by the government target of achieving 100% renewable electricity by 2030."[2]

Criteria used to evaluate options

Meridian agrees the overarching objective should be consistent with the Authority's statutory objective to ensure that any changes are in the long-term interests of consumers.

So long as that overarching objective remains paramount, we can see how additional criteria could aid in the assessment of options. While the Authority's criteria seem broadly reasonable, we query whether the second of those criteria could be better defined. It is not entirely clear to us what is meant by assessing the extent to which an option would "better align the incentives on purchasers and operators with the interests of end use consumers." The Authority could usefully clarify what purchasers and operators it is referring to, for example is it referring to spot purchasers, or purchasers of flexibility services, or both, (or something else entirely). Likewise, we assume the word operators is used to refer generically to generators and demand response providers but that could be clarified.

Meridian agrees that it is important the Authority consider the ability to undo any changes that are put in place if they do not provide net benefits to consumers. Some mechanisms may only be required in the short-term while the market transitions and more diverse flexible resources become available to the market.

[2] https://www.ea.govt.nz/assets/dms-assets/29/Concept-Report_-Review-of-generation-investment-environment-v3.pdf

Meridian agrees that the timeframes required to implement options is a critical consideration if action is to be taken ahead of winter 2023.

Options to better manage residual supply risk in winter 2023

Meridian comments below on each of the options contemplated by the Authority:

(A) Provide better information headroom in supply stack

(B) Provide forecast spot prices under demand sensitivity cases

(C) Improve the accuracy of intermittent generation offers

(D) System operator review of wind offers based on external forecast

(E) Clarify availability and use of discretionary demand control

(F) Introduce new integrated ancillary service

(G) Selectively increase existing ancillary service cover

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

(I) Review administered prices to apply in energy or reserve shortages

(J) Introduce hours-ahead market

(K) Procure additional resource outside of spot market.

We agree that these options are not mutually exclusive – multiple options might deliver optimal outcomes for consumers. Furthermore, it may not be possible to implement some options ahead of winter 2023 but benefits to consumers may still result from implementing options at a later date.

(A) Provide better information headroom in supply stack

We understand this option would result in the publication of the residual offer information used by the system operator. Meridian considers this a low risk option that could help to better inform thermal commitment decisions ahead of real time. We agree that publication on the WITS interface would be more user-friendly than on the system operator's website.

(B) Provide forecast spot prices under demand sensitivity cases

This option would see price sensitivity forecasts published by the system operator alongside the central price forecast. Meridian considers this to be a low value option with the sensitivity information only as valuable as the underlying assumptions. However, we accept that those making thermal generation commitments well ahead of real-time may be better placed to comment on the usefulness of such sensitivity forecasts.

(C) Improve the accuracy of intermittent generation offers

This option would amend the Code to require improvements to the forecasting of intermittent generation. This is a longer-term piece of work and that it is unlikely to be implemented for winter 2023. We understand that improved forecasting of intermittent generation could improve certainty and therefore the commitment decisions of slow responding resources ahead of real-time. Meridian can see the potential for longer-term benefits, and we will engage constructively with this option as part of any longer-term project initiated by the Authority. We understand that the Authority is already in conversations with intermittent generators about forecasting improvements.

(D) System operator review of wind offers based on external forecast

This option could be something of a stop gap prior to the option above being properly assessed. The system operator would undertake centralised wind forecasting and compare its own forecasts to wind offers, publishing any significant differences. If this can be done at low cost ahead of winter 2023 then it may be a useful temporary measure. However, to be useful the comparisons would need to be readily available to traders on an ongoing basis. In Meridian's opinion, the focus should be on:

- improving the forecasts of intermittent generation in offers; and
- any Code changes that would facilitate this improvement.

(E) Clarify availability and use of discretionary demand control

In Meridian's opinion, this option is worthy of further consideration. Currently the market does not have any visibility of the impact of ripple control or know when it will be used. Meridian agrees that "It is important to get much better information on these resources, and clarity on when they could be used." This could have a significant impact on the supply and demand balance during peak periods and on wholesale prices and commitment decisions from thermal generators or other flexibility providers.

We understand the option being contemplated would require distributors to bid their ripple control demand response into the spot market using the 'Dispatch Notification' product to be introduced in April 2023. The option would require Code changes, because there is not currently any incentive for distributors to participate in 'Dispatch Notification' and the only incentive is to use ripple control to manage any distribution network peak capacity constraints. The Authority considers a Code change and implementation to be feasible prior to winter 2023. In Meridian's opinion, this could significantly reduce uncertainty, improve commitment decisions, and improve the system operator's risk assessments. Distributors could collaborate to streamline bidding processes across multiple networks.

In the longer-term, distributors should have an incentive to provide this service to the wholesale market. Consumer or community trust owned distributors may see the long-term benefits to consumers of lowering wholesale prices at times of scarcity. However, not all distributors have this ownership structure. In the longer term, Meridian hopes that distributors will be able to commercialise the resource either through participation in ancillary services markets or through contracts. Real-time pricing will increase the incentives on retailers (particularly those short to spot prices) to procure demand response products like ripple control from distributors. Contract of this kind would require the development of technology to apportion ripple control in respect of each retailer's customers. Requiring distributors to bid the resource into the market would be a strong incentive to develop such technology to enable the commercialisation of the product.

(F) Introduce a new integrated ancillary service

Meridian agrees that the suite of current ancillary services reflects the historical needs of the New Zealand system and that those needs are changing. We therefore agree that there may be a case for a new ancillary service product to provide a buffer against unexpectedly large variations in demand or intermittent generation going forward as these risks increase in size. This reserve would need to be available for a longer duration than existing instantaneous reserves (i.e. several hours). This service would be equivalent to the standby reserve that exists in some other markets.

The Chief Executives' Forum has been independently considering whether such an ancillary service would improve system reliability and help to address the risks that are apparent in winter 2023.

The detailed design of this ancillary service would be critical and would need to ensure that resource providers tendering for the service are not simply swapping from participating in the spot market or existing ancillary services to offering the new ancillary service (if, as the Authority says, the latter is more remunerative). To justify the costs involved, any resources procured would need to be additional to what would otherwise be made available to the market so that it delivered a net improvement in reliability.

We agree with the Authority that one way to do that might be to ensure procurement is neutral between demand- and supply-side solutions, and co-optimised with the energy spot market and other ancillary services wherever feasible. In the longer-term, the ancillary service could incentivise new sources of demand response to be developed given the availability payment and low probability of being called on could be appealing to many consumers.

In the short term, ripple control could be offered into this ancillary service market. There may be complexities to the extent a distributor wants to retain some, or all, of its ripple control for the management of network capacity constraints during peak network demand. However, it is not clear to Meridian to what extent ripple control is necessary to manage distribution network capacity limits in each network – we understand that in many networks there may be ample headroom in terms of peak capacity limits. If that is the case, then there may not be any issues with offering ripple control as an ancillary service in the short term.

The consultation paper states at paragraph 5.33 that “costs should be allocated to causers as far as practical”. There is no further discussion on this point. More thought should be given to cost allocation for this option. For example:

- Whether causer pays or beneficiary pays would be better in principle for this service – to the extent intermittent generators are seen as the “causers” it may be that costs allocated to generators would flow through to wholesale prices and ultimately consumers anyway.

- If causers pay is preferred, how causers would be identified – this is far from clear in respect of the peak commitment problems currently experienced, which could be attributed to any combination of load variability, generation intermittency, thermal decision-making, lack of visibility or participation by demand response providers (as well as changes in incentives for ripple control), and a market design which does not incentivise commitment in the face of uncertainty.

In Meridian’s opinion a beneficiary pays approach is more likely to be efficient and lower cost to administer.

While considerable work on detailed design would be required, the system operator has indicated that it may be possible to implement a new integrated ancillary service in time for winter 2023. This is good news and Meridian would like to see the Authority investigate this as a priority. Code changes would be required along with changes to the details of the system operators Procurement Plan.

In Meridian's opinion, the Authority could consider implementing the ancillary service with a sunset date or a post implementation review date pre-established. In the longer term, real-time pricing and the incentives created by the market should be sufficient to enable contracts that reward consumer demand response and help to protect exposed retailers from high spot prices in times of scarcity. In this sense, the new ancillary service could be considered a provisional or interim measure to allow time for the emergence of new technologies and contractual relationships under real-time pricing. Investors in demand response (either at scale or aggregated) would need to see a pathway where the ancillary service would provide sufficient certainty and time horizon to invest now before transitioning to contractual relationships to deliver a return in the longer term.

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

Meridian understands that this option would procure greater volumes of instantaneous reserve and/or frequency keeping. In Meridian's opinion, procuring more of these existing ancillary services would not be a good fit to solve the reliability risks for winter 2023. Existing sustained instantaneous reserves are expected to be sustained for 15 minutes in response to a "Contingent Event" such as a failure on the grid or at a large generating station. This is distinct from the winter 2023 risk which, as discussed in the consultation paper, relates to resource inadequacy and lack of information and certainty for resources that must respond well ahead of real time with support required for peaks potentially across multiple trading periods.

The existing frequency keeping service is designed for generating units capable of quickly varying their output in response to instructions from the system operator to maintain frequency within the normal band. The requirements for quick variations in output to manage frequency would preclude many resources that could otherwise help to address the resource adequacy risks for winter 2023. In Meridian's opinion, procuring additional frequency keeping would be more likely to reduce generation that would otherwise be offered to the spot market and result in no net improvement in reliability on the system.

Meridian considers this to be an inferior alternative to option F.

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

This option would put in place arrangements similar to the payments made to customers during official conservation campaigns in dry years. However, the Authority seems to have in mind payments for shorter duration inability for generation to meet demand.

Meridian voluntarily made compensation payments to customers affected by outages on 9 August 2021. We did this because it felt like the right thing to do by consumers rather than any obligation.

We assume that the intent of this option would be to incentivise retailers collectively to contract with flexibility providers to help the system to address short-term reliability issues and therefore help the retailer to avoid the consumer payment. For example, a financial hedge could incentivise:

- an increase in commitment from a thermal generator counterparty; or
- investment in new peaking generation or demand response.

However, this option could be seen as punitive of retailers and could change the nature of the retail role. Currently retailers provide a financial service to bundle the costs that go into delivering electricity and help to remove price volatility for customers through billing. This option would instead imply that retailers have a responsibility for physical delivery of energy and are responsible for security of supply.

Meridian also agrees that the triggers and levels of compensation payment would have to be carefully calibrated and even then the likely impact of this option would be uncertain. The Authority has stated that it is unlikely the option could be implemented prior to winter 2023. Therefore, it does not seem worth considering at this time.

(I) Review administered prices to apply in energy or reserve shortages

A review of the level of administratively determined scarcity prices should occur periodically as a matter of course to ensure they reflect the actual costs of scarcity and appropriately incentivise investment. However, given the extent of analysis and consultation required we agree with the Authority's assessment that this option appears impractical before winter 2023. Even if it could be implemented in time it would alter long term incentives and a physical response to increase reliability in 2023 would seem improbable.

(J) Introduce hours-ahead market

The introduction of an hours-ahead market would be a significant undertaking and disruptive to the market and to investment certainty, at a time when ongoing investment is critical. In Meridian's opinion it is also unlikely that the additional complexity and costs would be justified by any benefit to consumers. Given the significant time and resources that would be required to develop this option, and the significant potential downsides, Meridian does not support this option.

(K) Procure additional resource outside of spot market

This option sounds like an inferior alternative to option F as it would seemingly:

- not co-optimise the additional resources with the spot market or require that resources be additional to those commonly offered into the spot market;
- be targeted at warming contracts for slow-start thermal generators; and
- have less rigour around efficient procurement processes.

Meridian agrees that this option could involve significant risks if providers withhold generation in the hope that a top up payment will be triggered (although we question whether such behaviour from generators would be possible under the trading conduct rules). We also see a risk that this option could undermine incentives to contract with providers of winter peak capacity to improve reliability since the system operator will procure resources anyway and socialise costs.

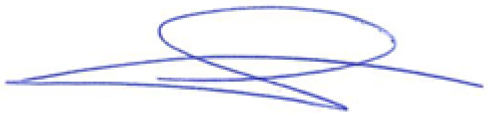
Meridian agrees that efforts would be better directed to other options.

Conclusion

At a high-level, Meridian agrees with the Authority that options A, B, D and E are candidates for more detailed work and could be usefully implemented ahead of winter 2023 to improve the information available. Meridian also supports option F to develop a new ancillary service and, subject to detailed design considerations, would support this occurring prior to winter 2023.

Meridian has also read a draft of the submission prepared on behalf of the CEO Forum and is generally supportive of that submission.

Nāku noa, nā



Sam Fleming

Manager, Regulatory and Government Relations

Appendix A: Responses to consultation questions

1.	Do you agree that operational coordination performance has become more challenging for the reasons indicated above? If not, what is your view and why?	Yes.
2.	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?	Yes.
3.	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?	Yes. However, options to directly increase reliability in the short term (e.g. option F) should also be considered.
4.	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?	Yes, subject to the improvements suggested in the body of this submission.
5.	What if any other options should be considered to better manage residual supply risk for Winter 2023?	The Authority has identified a comprehensive list of options.
6.	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?	Yes.
7.	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?	Yes, although the benefits may be minor. Thermal generators that need to make commitment decisions well in advance of real time will be better placed to comment.
8.	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?	Yes, although further consideration of this option may have merit in the longer term.
9.	Do you agree that the system operator should procure an external wind forecast and ask participants to review	If it can be done at low cost. However, Meridian considers improvements to

	their offers if there are large discrepancies between the forecast and offers? If not, what is your view and why?	intermittent generation forecasts in offers to be the priority.
10.	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?	Yes.
11.	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?	Yes.
12.	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?	Meridian considers this an inferior alternative to option F.
13.	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?	In Meridian's opinion, neither of those existing ancillary services would be well suited to address the risks apparent for winter 2023.
14.	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?	Yes.
15.	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?	Yes.
16.	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?	Yes.
17.	Do you agree that mechanisms that procure additional resources outside of the spot market should not be	Yes, Meridian agrees this should not be explored further.

	explored further for Winter 2023? If not, what is your view and why?	
18.	Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?	Yes, along with option F.
19.	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?	Meridian agrees that option F should be considered further. Option G appears to be an inferior alternative.
20.	Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?	Yes.
21.	What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?	Meridian has no further comment at this time.