CEO Forum submission to the Electricity Authority in response to the **Driving efficient solutions to promote consumer interests through winter 2023** consultation paper.

16 December 2022

Cover letter

CEO forum

This submission is made on behalf of a group of market participant companies known as the CEO Forum. This group of electricity sector CEOs meets periodically to discuss important industry matters where coordination is appropriate. A competition lawyer is in attendance at all meetings to ensure that commercial and competition matters are not discussed in the forum.

Reliability being undermined

We have become concerned that that the reliability of the system is being progressively compromised as the result of a number of effects that have become evident in the past two to three years and that the possibility of a disrupted system has risen to unacceptable levels. We're pleased the Authority agrees with the urgency (as per letter of 12 Dec), but the consultation paper places its emphasis on **driving efficient solutions to promote consumer interests through winter 2023** but we think the issue is **driving adequate *reliability* to promote consumer interests through winter 2023**.

Long term interests of consumers

At any time a disrupted system would come at a cost to the long term interests of consumers but that is especially the case in the current environment. The government's legislated carbon emissions goal and recently released Emissions Reduction Plan rely on consumers large and small electrifying industrial processes, transport and any other uses being made of fossil fuels that can be switched. The incentive to meet demand with renewable generation has, to date, largely brought investment in intermittent generation into the system which is less reliable in supplying demand at all times than generation from thermal plants or stored hydro. The result is a near term risk of a disrupted electricity system which, to the extent it would create uncertainty and hesitancy on the part of consumers, has a considerable cost.

The unit commitment problem and the visibility of available demand response

The paper recognises the challenge thermal generators face absorbing the cost of committing thermal units to run and the risk that the actual run time turns out to be uneconomic i.e. the unit commitment problem. The paper notes that these costs have increased in recent years exacerbating the problem. We think that the paper may have understated the significance of the issue during this period while we wait for the much needed new investment to take place.

We have become aware through the process of preparing this work that in addition to the unit commitment problem there is a significant amount of demand response not necessarily made available to the (energy or instantaneous reserves) market for a variety of reasons.

For example, up to the point where RCPD applied distributors had an incentive to manage their load in the peaks. Since the introduction of TPM this incentive is weakened and each distributor is determining their own priorities and own practices with load control. Some already offer interruptible load in the instantaneous reserves market. The introduction of Dispatch Notification in 2023 may not be an option available to all distributors, or influence their incentives to participate.

We note there is also other potential demand response available amongst industrial and commercial processes that is not in the market. Real Time Pricing and Dispatch Notification may bring some of that to market but not necessarily quickly enough for winter 2023 and not necessarily all such demand response potential.

An ancillary service product that provides payment for making that potential response available for muti hour service with a multi hour notice would encourage participation and, at the same time, provide certainty where a low residual situation is unfolding.

The case for intervention

When demand growth was more sedate and options for generation investment were unfettered compared to today's environment, privately optimal choices and economically efficient choices tended to be in-step as we saw in the electricity market from 1996 until recent times. In the market today, where demand is rising and supply is being increasingly met by intermittent renewable generation but investment in more flexible generation and demand response for periods of low intermittent generation is has not been able to keep up, the evidence is that the risk of shortfalls has risen to an unacceptable level. We are confident that this is a temporary situation and note that the case for intervention at this juncture is not new or novel. K Gillingham (2010) observed:[1]

> Economic theory can provide guidance and more rigorous motivation for renewable energy policy, relying on analysis of the ways privately optimal choices deviate from economically efficient choices. These deviations are described as market failures and, in some cases, behavioral failures. Economic theory indicates that policy measures to mitigate these deviations can improve net social welfare, as long as the cost of implementing the policy is less than the gains if the deviations can be successfully mitigated.
> If markets will not motivate transitions at the appropriate speed or to the appropriate renewable supplies, the question becomes whether policy interventions can address these market failures so as to make the transitions closer to the socially optimal.

The design of the electricity market is a matter for the Authority, per its statutory objective, rather than policy. Even so, neither the high risk of disruption, nor the actual occurrence of disruption, is in the long term interests of consumers and a market design "intervention" is warranted.

We note that this need was raised in the "Hodgson Report"[2] on the events of August 9 2021 and again by MDAG in their recent paper:

> We also see merit in a new ancillary service to reflect the changing risk profile on the system. Such a new service should harness the full range of potential resource providers including batteries and demand-side flexibility, be co-optimised with the wider spot market and conform to causer-pays principles (Option A4)[3]

A temporary ancillary service, under urgency, focused on ensuring reliability for Winter 2023 would also be consistent with MDAG's proposed timeline of a permanent new ancillary service for 2024. It would also be consistent with MDAG's principle of "learning by doing".

Security of Supply standards

The trail the paper lays for consideration of the "efficient solutions to promote consumer interests through winter 2023" starts with the security of supply standards set out in the Code which go to reliability rather than efficiency.[4] The standards are based on the Security Standards Assumptions

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[1] Kenneth Gillingham and James Sweeney, Yale University, Market Failure and the Structure of Externalities (2010)

[2] **Investigation into electricity supply interruptions of 9 August 2021** (the Hodgson report),

[3] MDAG, Price discovery in a renewables-based electricity system – options paper (December 2022)

[4] See clause 7.3(2) of the Code

released in 2012. These standards are predicated on an assessment of the winter capacity margin (WCM) calculated using expected available capacity which is, in turn, a function of installed capacity allowing only for forced and scheduled outages.

The WCM standard is not working in the current circumstances

The paper notes the "increased frequency of tight balance between supply and demand" and acknowledges the "New Zealand electricity system (like many others) currently uses a self-commitment approach to coordination availability decisions." The unit commitment problem occurs where a generator's assessment of total expected production costs over the scheduling horizon, including total fuel costs, start-up costs and shut-down costs, exceeds the expected revenue and the participant elects to not offer the unit into the market.[5] As a result the balance between supply and demand is not a function of installed capacity as per the standard it is a function of capacity made available which is proving to be demonstrably different to the basis that the standard has been determined on.

The paper describes the cost implications of committing a unit and incurring start-up costs while prices may not turn out to be as per the forecasts at the time. There is also the risk that commitment decisions are made but prices turn out to be lower. Therefore, the paper is understating the unit commitment problem and harnessing economic demand response has an important role.

Generation residual measure of "tightness"

The System Operator relies on the concept of the **generation residual** to meet its PPOs.[6] The System Operator issues low residual CANs where "market schedules show only 200 MW of *residual* remaining for given times".[7] The generation residual is the System Operator's estimate of the balance of supply and demand where supply is based on capacity made available and not installed capacity as used in the standard.

No review of standards or recognition of the need in the paper

The paper places a lot of weight on the quality of forecasts and incentives that owners of thermal units rely on. We endorse some of the recommended improvements along these lines suggested in the paper. However, the paper fails to test the standards themselves and their relevance for maintaining security in the current environment. The Authority reviewed the standards in 2017 and released a statement that included these points:[8]

> The standards were last reviewed and amended in 2012.
> The completed review showed that some changes to the security of supply standards may be warranted. However, the benefits of amending the standards at this time are limited because the effect of any potential amendments would be minor.
> To reduce the regulatory burden on stakeholders we will not propose any changes at this time or issue a paper for consultation.
> We do however intend to review the standards again sooner than the regular five-yearly period.

There is no record of a review of standards having been conducted over the five years since this note and a great number of changes have occurred that impact on the reliability of the system during that time. The Authority's statutory objective includes promoting reliable supply by the electricity industry for the long-term benefit of consumers. The importance of a resilient electricity system is

[5] Paras 4.17 – 4.28 provide a description of this issue. The discussion only focuses on the probability of higher prices and ignores the possibility of committing a unit and prices turning out to be lower.
[6] See clause 7.2 of the Code
[7] Transpower, Notices for insufficient generation See: SO_notices_insuffient_generation
[8] See Electricity Authority website: EA_development_on_winter-energy

rising and reliability is demonstrably weakening.[9] At this time the standards themselves should be scrutinised and one of two physical options considered in the paper should be given more weight than “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” or the cost of forced outages “would be difficult to quantify but could be appreciable”.

A winter peak ancillary service product

We have taken the design of a winter peak ancillary service for winter 2023 as far as we can. It would require an urgent Code change[10] so would expire at the end of winter 2023. That would leave from now until winter 2024 to fully work through the options for ensuring the market provides secure electricity supply through the transition to a more renewable energy system.

An integrated solution would be ideal but there is a trade-off between developing an integrated product and getting a product operationalised by winter 2023. It may be that there is only time to tender for the duration of winter 2023 and operate a merit order of product available based on the fees of the various providers to meet each unique situation. An administered price may also be required for the periods the product is activated in order to preserve market price signals, for example to hold prices at the levels that would otherwise have existed but for activation of the product. This would mitigate the dampening of price signals to invest in or operate flexible generation or demand response for peak periods while still addressing the short term reliability risk in the wholesale market.

We recommend the Authority pursue the winter peak ancillary service product we have developed with urgency. Of the options presented in the paper it is the only one that will actively and immediately address the current situation and the interests of consumers which would be impacted in the long term if reliable supply by the electricity industry is not addressed adequately.

Submission

Our submission is made up of two parts:

1. A submission in response to the consultation paper including a proposed problem definition and discussion about the reliability and security standards the market relies on
2. Detailed design work for a winter peak ancillary service product along the lines of the paper’s option F - a new integrated ancillary service.

[9] See: **Investigation into electricity supply interruptions of 9 August 2021** (the Hodgson report), the **Security of Supply Assessment of 2022** (SOSA), Transpower’s **Weekly Market Movements** Week Ended 16 October 2022 and the **System Operator Winter Review Paper** (released 10 November).

[10] As per the Electricity Industry Act 2010 s 40 (1)

Response to Submission

Problem definition

The problem is, as we see it, that a number of influences have converged to create a transitory reliability problem. Either the price signals are inadequate and/or or the time it will take for new investment to come to market means that security of supply is undermined. Security of supply is to the benefit of all consumers even though there are ways of differentiating preferences and for parties to enter into private arrangements. However, everyone benefits if security of supply meets the agreed standards. Our proposal is for a short term solution and we think the cost to consumers of that solution will be lower than the consequences of disruption if they were to occur. We think some of the measures the Authority suggests should be pursued in any event, but our focus is squarely on winter 2023. Accordingly we propose the following problem definition against which to view the options in the paper and our proposal:

1. The current suite of market mechanisms and ancillary services is no longer adequately delivering the security standard in the face of higher peaks, more frequent high peaks and the increasing challenge for unit commitment of thermal generators.
2. The market has no mechanism to immediately deal with the unit commitment problem. RTP will deal with one element of the uncertainty but commitment decisions will still be made ex ante based on forecast prices.
3. There is no ancillary service product available to manage multi-hour shortfalls in advance. (As noted in the Hodgson report and the recent MDAG report).
4. The long term interests of consumers will be served by the introduction of a multi hour, firm response, ancillary service to reduce the risk of supply disruptions in winter peaks before winter 2023. Providers of firm response could include generation or demand curtailment providers or batteries and ideally come from resources not currently participating in the market.

Reliability and Security standards

The consultation paper frames the discussion around the fact that "reliability standards reflect consumer benefits". It addresses the ideal level of reliability through the lens of the security of supply standards set out in the Code. Clause 7.3(2) stating:

> The capacity security of supply standard is a winter capacity margin of 630-780 MW for the North Island.

This is based on the Security Standards Assumptions Document released in 14 November 2012. The consultation papers states :

> Current arrangements appear to have delivered satisfactory security of supply for many years and will continue to do so. However, there are some recent signs that operational coordination is becoming more challenging with potential adverse implications for reliability.

The paper concedes that :

> 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, it does raise some questions.

We submit that the consumer benefits are undermined at the current level of reliability and the elevated risk of electricity supply disruption. In our view relying solely on the initial set of options that appear most attractive based on the stated objective and current information is not in the long term interests of consumers.

We submit that the Authority should proceed to introduce a multi hour winter peak ancillary services product with urgency for Winter 2023. This is in the long term interests of consumers for four reasons:

1. The circumstances and tensions in the electricity market in 2022 are quite different from 2012 when the security standards were adopted
2. Measuring actual shortages as per the paper doesn't reveal the effort taken to avoid shortages, the number of near misses and the uncertainties in the system on winter peaks that have to be managed.
3. The security standard is based on installed capacity, and fails to account for the unit commitment problem even though it is a well understood issue.
4. The problem is narrowed to "growing information or incentive problems" rather than the broader challenge of maintaining reliable physical supply by the electricity industry in 2023 and beyond for the long-term benefit of consumers

We address each of these in turn.

Conditions in the electricity market in 2022 are quite different from 2012

In 2012 demand was still expected to roughly map GDP growth or possibly rise more slowly than GDP for a variety of reasons. Generation investment was expected to replace retiring plant and meet demand growth in response to investment signals from the wholesale market (i.e. combined spot and forwards markets). In 2012 there was little if any reference, at a government policy level, to the possible need to force the removal of thermal generation and increase renewable electricity generation to satisfy a massive increase in electricity demand.

In the period 2017 – 2022 a number of dynamics changed which has meant the resulting scenario in 2022 is quite different to the market in 2012 when the security standards were being determined:

1. The prospect of a net zero carbon goal and a high target percentage of renewable generation was first signalled in the confidence and supply agreement between the Labour party and the Greens in late 2017.
2. Government signalled their desire to rein in gas production with the ban on offshore oil and gas exploration in 2018.
3. An Interim Climate Change Committee was asked to explore how to achieve accelerated electrification with their public report released in 2019.
4. Owners of thermal generation and potential investors in new thermal generation cooled any plans they had for investment while they digested the more explicit policy direction resulting from the decarbonisation agenda.
5. The carbon price has risen from around \$16 to \$18/tCO2 in 2017 to circa \$80 /tCO2 through 2022. The average coal price has risen form \$63 NZD/mt in 2017 to \$274 NZD/ mt in 2022.
6. Modelling by Transpower and the Climate Change Commission showed demand will increase significantly as a result of electrification. Transpower wrote in its Te Mauri Hiko – Energy Futures white paper in 2018:

> As the New Zealand economy electrifies in pursuit of the most cost-efficient and sustainable energy sources, electricity demand is likely to more than double from ~40 terawatt hours (TWh) per annum today to ~90 TWh by 2050.

7. Gas supply disruptions caused significant price volatility from late 2018 into 2019 showing how dependent electricity supply is on stable gas supply.
8. The combined impact on the need for generation investment in the face of less thermal generation and higher demand from electrification saw generators dust off investment plans but the scale of investment required and the challenges getting it consented have become apparent.
9. Genesis has been signalling that the economic life of its Rankine thermal units at Huntly is limited but continues to take steps to extend the life of these units. The paper recognises the importance of the Rankines in providing security of supply and the cost pressures where it might be called on for short term running.
10. The Authority wrote, with respect to the impact of the new Transmission Pricing Methodology (TPM) on behaviour forming the peaks:[11]

> While we base our calculations on forecasts for 2021, we do not expect results to be particularly sensitive to the exact year of the implementation of the TPM changes. This is because the near term winter capacity margin has been relatively stable through time. For example, the near-term margin has ranged between 1050 MW and 1200 MW in the past 6 years and is projected to be around the middle of that range in 2021. Hence, we expect the projected 2021 conditions to represent a reasonable 'starting point' from which to assess the effect of potential TPM changes.
> In our view, the assumed TPM changes are unlikely to have any material impact on the projected WEM because:
>
> - The RCPD signal only affects behaviour for about 100 hours a year, meaning its effect on energy-related decisions (such as hydro storage and thermal fuel management) is relatively small.
> - To the extent that DR does occur in energy shortage periods, it is mainly driven by nodal prices (or arrangements linked to those prices) – and these incentives are not expected to be reduced by the TPM changes.
> - Most DG has relatively low short run marginal costs (SRMCs). The operation of this plant during periods of tight energy supply (such as 'dry years') is therefore unlikely to be affected by the assumed TPM changes, given that nodal prices are expected to be elevated during such periods.
>
> For these reasons, this analysis focuses on how the TPM changes are likely to affect the WCM. The WCM is calculated according to a formula set out in the Security Standards Assumptions Document (SSAD) which determines the extent to which expected North Island capacity, supported by available South Island capacity, exceeds expected North Island demand during winter peak periods. A positive margin is required to cover unexpected events such as generation plant outages, transmission outages, or unusually high demand.

As is the case with this paper the TPM analysis relied on installed capacity rather than available capacity which is problematic during the transition to high levels of renewables and significantly higher load from decarbonisation.

11. The System Operator advised the market:

[11] Electricity Authority Peak charges under proposed TPM guidelines Information paper and next steps March 2020

> An increase in variable and intermittent renewable energy sources, i.e. wind and solar PV, will make balancing demand and generation more challenging and is likely to result in more frequency fluctuations.[12]

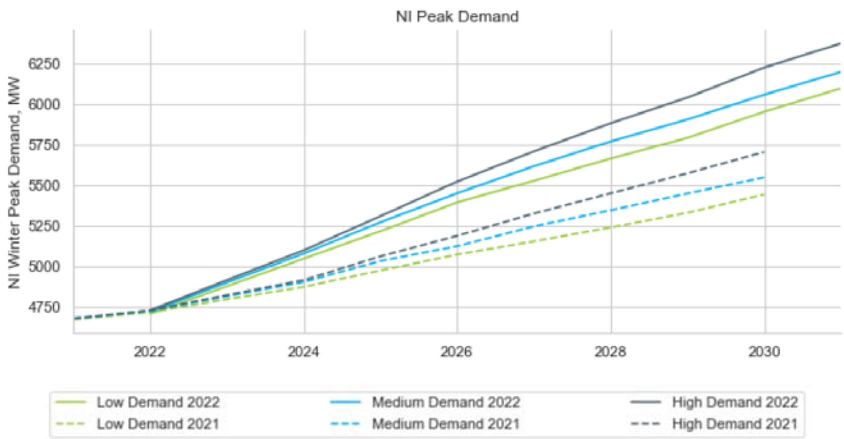
12. The report into the events of August 9 2021 found:[13]

> The electricity system's arrangements for generation shortfalls that may last for part of a day are very much less mature than arrangements for instantaneous and short outages (spinning reserve), and that that immaturity was at play on 9 August. We call this issue 'managing multi-hour shortfalls'. We think it will become an increasingly important issue to address.

The report recommended:

> *That the EA and the SO design and implement a new product to manage multi-hour shortfalls.*

13. The 2022 SOSA increased its expectations of NI Peak demand over expectations of a year earlier as shown below:



The System Operator wrote:

> Existing and committed generation is sufficient to maintain the NI-WCM above the upper security standard through to 2024;

This is consistent with the calculation of the security standard but doesn't account for the unit commitment problem.

14. The System Operator wrote in November 2022 it has observed significant peak demand growth in 2021 and 2022:[14]

> In the last 10 years, New Zealand's top 10 largest peak demands all occurred in the past two winters and six out of those 10 occurred in 2022. The grid emergency on 9 August 2021 saw a record high New Zealand peak demand.

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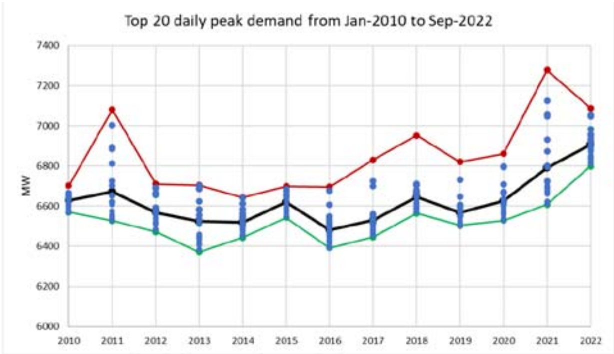
[12] Transpower, **Opportunities and challenges to the future security and resilience of the New Zealand power system** November 2021

[13] **Investigation into electricity supply interruptions of 9 August 2021** (the Hodgson report),

[14] **System Operator Winter Review Paper** (released 10 November).



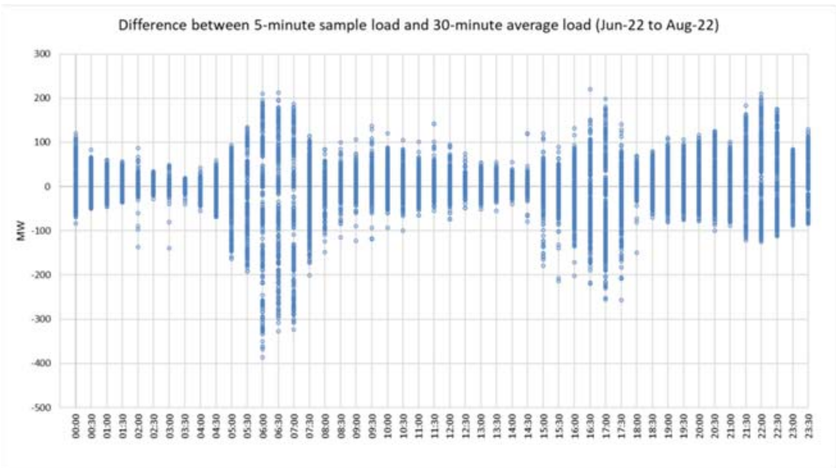
15. The System Operator also noted in November 2022 an increasing incidence of low residual situations. The System Operator also noted an increase in situations where there were actually insufficient generation offers: [15]

> The system operator issued four low-residual CANs in 2019, none in 2020 during covid lockdowns 10 low-residual CANs in 2021 and 13 in 2022.
>
> The system operator issued no GENs in 2018, 2019 or 2020 relating to insufficient generation offers then three such GENs in 2021 and two in 2022.

16. The System Operator analysed load variation within a trading period. It observes can mean a significant difference between what is forecast as the average demand across the 30-minute trading period and actual demand at 5-minute intervals. While the market is generally interested in the 30-minute forecast average, the System Operator needs to understand load variation patterns within a trading period to ensure system security throughout its duration.[16]

> The analysis is set out in [the figure below] demonstrates that real-time load variations can be up to 200 MW greater than the 30-minute average demand. This is a significant difference in the context of the increasing proportion of intermittent generation and the limited flexibility of half the thermal generation capacity. For example, 200 MW of residual generation in the forecast schedules based on the 30-minute average (i.e. outside the low-residual parameters) could end up as 0 MW in real-time based on load variation alone. This means peak capacity requirements could be even greater in real-time than the thermal scenarios demonstrate.

Load variation within trading periods, winter 2022



[15] ibid
[16] ibid

17. The government's legislated carbon goal and recently released Emissions Reduction Plan rely on consumers large and small electrifying industrial processes, transport and any other uses being made of natural gas that can be switched. A disrupted electricity system would create uncertainty which would lead to a considerable cost which is not in the long term interests of consumers.
18. MDAG said in their recent paper:

> We also see merit in a new ancillary service to reflect the changing risk profile on the system. Such a new service should harness the full range of potential resource providers including batteries and demand-side flexibility, be co-optimised with the wider spot market and conform to causer-pays principles (Option A4)[17]

Actual shortages don't reveal the effort taken to avoid shortages, the number of near misses and the uncertainties in the system that have to be managed at the point in time.

The Security Standards Assumptions Document describes the estimated capacity and energy margins where total costs to consumers will be minimised. The consultation paper says:

> The published analysis showed that if the system was achieving the capacity standard, about 16-28 hours of 'shortage' should be expected each year, where shortage means either a shortfall in normal instantaneous reserve cover (the more likely outcome) or forced load shedding (less likely).
>
> 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.

Quoting actual shortage hours ignores the reality of the System Operator's effort focusing on meeting its PPOs 24/7 i.e. the actual 2.25 hours of reserve or energy shortage reported doesn't reflect near misses.

The System Operator issues low-residual CANs when it calculates there is < 200 MW of residual generation for an upcoming trading period. Where participant responses to a low-residual CAN are insufficient or system conditions worsen, the System Operator may declare a grid emergency and issue a GEN.

In the period following the issuing of a low residual CAN the System Operator calls:

- Market participants to ensure their offers are accurate and to make additional capacity available.
- Grid Owner to consider changes to outages that may increase available generation.
- Distributors, direct connects and retailers to be aware and prepare for potential impacts or requests.

As the signalled period of potential tightness approaches the System Operator will focus on requesting distributors reduce any load control not already offered into the market as interruptible load in the Instantaneous Reservices market. The paper comments on this as follows:

> 4.52. This response can be significant in size 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 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

[17] MDAG, Price discovery in a renewables-based electricity system – options paper (December 2022)

> 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.

What the paper says about this is fine but misses some important features of this arrangement:

1. Following the removal of RCPD with the introduction of the new TPM there may be issues accessing this service because the incentive to actively manage peaks is weakened. The removal of RCPD will also have impacted on the appetite for distributors to invest in DG to generate during peaks.
2. Distributors aren't paid to respond to the System Operator's requests for load control so incentives to respond, or to maintain the ability to respond, are weakened.
3. The ability for distributors to control load doesn't ensure adequacy in the event that load is already being controlled heavily, demand spikes beyond forecast load and/or intermittent generation drops suddenly by more than is expected.
4. The amount of load distributors can collectively drop in response to requests from the System Operator is not clear. The paper acknowledges the lack of clarity around "discretionary" demand curtailment volumes and use.
5. Demand side market enhancements, such as Dispatch Notification implemented as part of the real-time pricing project, may address "some of this market visibility issue" but it won't address all of it and risks remain with relying on this solution in 2023 given the precarious challenge of meeting peak winter demand in the NI.
6. The simple point is that there is economic demand response not being made available without Transpower intervention.

The standard is based on installed capacity not available capacity

In the Security Standards Assumptions document WCM is determined using the following formula (all units in MW):

$$WCM = (EACNI - EDCNI)$$

where:

EACNI is North Island expected available capacity;

EDCNI is North Island expected demand for capacity;

North Island expected available capacity (EACNI) must be determined by the following formula (all units in MW):

$$EACNI = TCNI + HCNI + WCNI * WCF + OCNI$$

where:

TCNI is the installed capacity of North Island thermal generation sources, allowing for forced and scheduled outages;

HCNI is the installed capacity of North Island controllable hydro schemes, allowing for forced and scheduled outages, and de-rated to account for constraints which affect output during peak times;

WCNI is North Island wind capacity;

WCF is a wind capacity contribution factor; and

OCNI is the expected generation available in winter daytime from other North Island generation types (including geothermal, cogeneration, solar and uncontrolled hydro schemes).

This approach defines a standard based on installed capacity. The problem facing the market currently includes the frequency of tight residual situations and a significant contributing factor to that tightness is the unit commitment problem. The paper does not note the disconnect between the current situation and the 2012 standards assumption.

The Authority reviewed the standards in 2017 and noted:

> These standards are key parts of the framework for monitoring medium-term security of supply. They assess what an efficient level of generation surplus would be to minimise the sum of the costs of providing generation, **plus the costs to consumers from outages caused by insufficient generation being available**.
>
> The completed review showed that some changes to the security of supply standards may be warranted. However, the benefits of amending the standards at this time are limited because the effect of any potential amendments would be minor.
>
> We do however intend to review the standards again sooner than the regular five-yearly period. We have made improvements to our modelling tools to make it easier to undertake more frequent reviews.

The WCM has been set in a way that fails to recognise the unit commitment problem and the System Operator is managing the system using a residual that recognises the unit commitment problem but is not defined in the Policy Statement. The paper:

- does not consider a review of the standards forms part of this consideration and
- does not consider that the residual might need to be formalised and made more transparent

The problem is narrowed to "growing information or incentive problems" rather than the risk of maintaining reliable physical supply in 2023 for the long-term benefit of consumers

The paper acknowledges that New Zealand has a self-commitment approach to availability decisions and that the impact of this has become more acute in the current circumstances. The reliability issue is created where installed capacity differs from available capacity because of the unit commitment problem. This is where the generator is reluctant to offer a unit because of the uncertainty over whether the costs of start-up and dispatch and shut down will be profitable. It is one of a number of issues that contributes to the challenge of operational coordination.

We agree with the paper where it says:

> 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.

The paper narrows the problem definition as follows:

> 3.11. 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.

The paper acknowledges that there are signs that operational coordination issues are becoming more challenging. It says:

4.17 Three recent factors may be making unit commitment decisions more challenging especially for slower starts thermal generation (discussed in paras 4.17 – 4.28):

- Higher fuel and carbon costs have raised start costs for thermal plant
- Rising intermittent generation makes forecasts more uncertain
- Changing role of thermal generation means more frequent start decisions.

We would add:

- There may not be enough peaking capacity in the NI to address emerging peak load patterns
- Plant not suited to peaking (e.g. the Rankines) have to make potentially costly decisions to be available
- Recently revealed volatility in real time load variations

The emphasis on growing information and incentive problems ignores the convergence of the other problems and that their trends have led to the problem of maintaining physical reliability in winter 2023. The risk is the heightened risk of supply disruptions which, if they eventuate , will impose a significant cost on consumers

Submission

Submitter: CEO Forum

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?	Yes but the paper doesn't fully recognise all of the influences at play and the risks they now pose to reliability.
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?	No. The questions narrows the problem to information challenges or misaligned incentives leaving the issue of the effectiveness of the standards, the use of the residual and the lack of physical response certainty unaddressed. It ignores the changes that the market has experienced in the past five years that have manifest themselves in weaker reliability right at the time (large and small) consumers' long term interests are most vulnerable to supply disruptions.
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?	Yes, but not to the exclusion of other measures the Authority should consider given the nature of the broader problem and significance for reliability in the long term interests of consumers

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?	No. If the Authority confines itself to these the physical risk of supply disruption in 2023 will not be adequately addressed. The proposed evaluation criteria do not include ensuring the level of physical reliability in 2023 is consistent with the long term interest of (large and small) consumers.
Q5. What if any other options should be considered to better manage residual supply risk for Winter 2023?	We have provided a developed solution that would address reliability in 2023 and provide a basis for developing an enduring solution subsequently. The solution we have developed is not instead of better information and incentives it would be as well as.
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?	Yes
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?	Yes
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?	No view. Our focus is on an immediate solution that will provide for adequate system reliability in 2023
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?	No view. Our focus is on an immediate solution that will provide for adequate system reliability in 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?	Yes, but we still consider that reliance on the use of demand control without a commensurate incentive or compensation will lead to less investment and innovation in demand-side technology over time.
Q11. Do you agree that work should be undertaken on a new integrated ancillary	We recommend proceeding with a multi hour winter peak ancillary service that operates along the

service for winter 2023 to help manage increased uncertainty in net demand? If not, what is your view and why?	same lines as frequency keeping i.e. not integrated in the market solution, but integrated operationally in the same way frequency keeping is.
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?	No. The problem is more serious than this. Better to adopt our proposed solution of a multi hour winter peak ancillary service product with an urgent code change and work on an enduring solution in the meanwhile. There is a risk of unintended consequences with this approach.
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?	NA
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?	No view. Our focus is on an immediate solution that will provide for adequate system reliability in 2023, and can reward participants, including demand management, directly
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?	No view. Our focus is on an immediate solution that will provide for adequate system reliability in 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?	No. We recommend proceeding with a multi hour winter peak ancillary service that operates along the same lines as frequency keeping i.e. not integrated in the market solution but integrated operationally.
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?	Yes
Q18 Do you agree that options A, B, D, and E appear attractive and should be progressed further? If not, why not?	Yes but not to the exclusion of proceeding with a multi hour winter peak ancillary service that operates along the same lines as frequency keeping i.e. not integrated in the market solution but integrated operationally. Also, option E includes the possibility of the Code requiring distributors to utilise the Dispatch Notification product to notify the SO of HW heating load available for shedding when the system is

	becoming tight. Distributors rely on load control for a variety of purposes including network security , investment and consumer signals. Forcing them to bid it via Dispatch Notification would interfere in their ability to manage their own resources at their own discretion. Such a move would have to be well thought through and consulted on in its own right.
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?	No. We recommend proceeding with a multi hour winter peak ancillary service that operates along the same lines as frequency keeping i.e. not integrated in the market solution but integrated operationally. We do not recommend pursuing G
Q20 Do you agree that options C, H, I, J and K should not be progressed further for winter 2023? If not, why not?	Yes
Q21 What if any other matters should be considered when assessing options to better manage residual supply risk for Winter 2023?	The long term benefit of consumers is not served by winter peak shortages should they occur. Consumers large and small are being encouraged to electrify their industrial processes and homes. The evidence is that the risk of emergency situations occurring and possible shortages has increased to an unacceptable level. The cost of significant disruption will be high for all consumers and that is not in their long term interests. The paper dismisses the issue of whether forced power cuts would impose any costs that are broader than the foregone electricity consumption on the basis that the “cost would be difficult to quantify but could be appreciable”. In the context of the statutory objective regards seeking reliability in the long term interest of consumers (alongside competition and efficiency this seems inconsistent with what might be at stake.

Detailed design work for a winter peak ancillary service product along the lines of the paper's option F - a new integrated ancillary service.

In this section we:

1. Set out the product in the context for maintaining security of supply in real time,
2. Set out the attributes, definition and purpose of the product,
3. Provide some initial Code drafting and
4. Provide some drafting for inclusion in the Procurement Plan.

We do not go as far as suggest changes to the Policy Statement or introduce tender documents,

A winter peak ancillary service product

Transpower holds the position of System Operator as a service provider role in the New Zealand Electricity Market contracted to the Electricity Authority who are the Market Operator. [18]

> The System Operator must carry out its obligations under this Code with skill, diligence, prudence, foresight, good economic management, and in accordance with recognised international good practice, taking into account—
>
> (a) the circumstances in New Zealand; and
>
> (b) the fact that real-time co-ordination of the power system involves complex judgements and inter-related events.

The System Operator is obliged to meet principal performance obligations (PPOs) set out in the Code. [19]

> **7.2 Principal performance obligations of the system operator in relation to common quality and dispatch**
>
> The obligations in clauses 7.2A to 7.2D are principal performance obligations.
>
> 7.2A System operator to maintain frequency
>
> (1) The system operator must dispatch assets made available in a manner that avoids cascade failure of assets resulting in a loss of electricity to consumers arising from—
>
> (a) a frequency or voltage excursion; or
>
> (b) a supply and demand imbalance.

Part 8 of the Code sets out the requirements of the Policy Statement which is prepared by the System Operator and submitted to the Authority for approval:[20]

> **8.11 Content of draft policy statement**
>
> (3) The draft policy statement must include—
>
> (a) the policies and means that the system operator considers appropriate for the system operator to observe in complying with its principal performance obligations;

One of the processes the System Operator carries out in its role of maintaining the efficient workings of the market and meeting its PPOs is to forecast electricity supply and demand across the country in 30-minute trading periods throughout the day.

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[18] Code 7.1 (A) 1

[19] Electricity Industry Participation Code 2010 Part 7

[20] Electricity Industry Participation Code 2010 Part 8

The System Operator keeps track of the residual in forward schedules being the offered generation less the cleared generation minus an allowance for the frequency keeping band in each island. This is not the same as the standby residual shortfall which is the generation and reserve shortfall after the loss of the largest risk (the energy residual calculation) or the generation and reserve shortfall to cover the loss of the next largest risk (after loss of the largest risk on the system). To date the System Operator does not publish the residual that it can see in forward schedules but that may change.

A residual threshold of 200MW is an internal standard that the System Operator currently uses in its approach to meeting its PPOs. It captures the load forecast i.e. half hourly average demand expected during the relevant trading period and intermittent generation in the cleared generation. Instantaneous peaks (especially during morning and evening peaks) may be up to 200MW higher than forecast and intermittent generation can fall suddenly by 200MW.

Given the role of the residual in the System Operator's approach to meeting its PPOs it should be referenced in the Policy Statement.

If a generation residual (i.e. a reserve deficit or energy deficit) is showing in the forecast schedules, or is close to showing, the System Operator will issue various notices to the market informing of the risk. These notices advise participants of the issue, the actions requested from participants, and the actions the System Operator will take if an issue is not resolved.

A Customer Advice Notice (CAN) is not a formal notice per the policy statement, it is used for sending a wide variety of information to market participants, interested parties or stakeholders. It can be issued any time from one week out to four hours before a particular time. The trigger for a low residual CAN is market schedules that show only 200 MW of residual remaining for given times. The intended purpose of a CAN is to warn that a tight point is coming up in the one week to four hour timeframe and request action or preparations from participants

A formal notice must be issued by the System Operator when the ability of the System Operator to comply with the principal performance obligations is at risk or is compromised.[21] A Warning Notice (WRN) can be issued one week to gate closure (one hour ahead of real time). The Policy Statement describes a Warning Notice as a formal notice which advises participants that grid emergency conditions are anticipated. [22] The trigger for a WRN is a forecast deficit at given times. The intended purpose of a WRN is to request participants to take action at the times given, and to warn participants of potential consequences if the issue is not alleviated.

A Grid Emergency Notice GEN is also a formal notice and used to declare a grid emergency. [23] This is the situation where either a forecast deficit or a real-time deficit is seen after gate closure. The intended purpose of a GEN is to allow market participants to reoffer, to request participants respond to actions, and to warn of the consequences if the requirements are not met.

During this sequence of notices and escalation the System Operator must rely on participants taking action within the market mechanisms. The only action available to the System Operator is to shed demand once the grid emergency event begins to unfold. At some point after issuing CANs, and possibly WRNs, but before having to issue a GEN the market would benefit if the SO was able to access a tool available to the SO that gives them the ability to reduce previously contracted load with absolute certainty. This is what is referred to in the Hodgson Report as a multi hour product i.e. a product that can be activated before the event and remain in effect for over 1 hour.[24]

[21] Clause 5 of Technical Code B

[22] Policy Statement 62A.3

[23] Policy Statement 62A.1

[24] MBIE, Investigation into electricity supply interruptions of 9 August 2021, 4.6 The market needs better price risk management tools (This investigation was commissioned by the Minster of Energy and Resources and led by Pete Hodgson with specialist technical advice from Erik Westergaard and secretariat support from MBIE. It is referred to colloquially as the Hodgson Report.) November 2021

At present one of the tools System Operator relies on is calls to EDBs to shed load that would not normally respond to, nor participate in, the wholesale market. For the most part EDBs do as much as they can on such requests. However, they are not paid for the service, have weak incentives to provide the services (until a supply shortage declaration is in force at which time they are obliged to respond as the System Operator instructs in writing per 9.15 and 9.16 of the Code), use load for their own purposes (specific network investment purposes, to manage constraints, and to manage pass through costs to customers) and the volumes available are not precisely know in every case. Several EDBs already offer some of their hot water load into the instantaneous reserves market, hence it is already participating in the market and assisting with system security.

Real Time Pricing was recently introduced to the market mechanisms and Dispatch Notification provisions are about to be introduced. These products will not eliminate the unit commitment problem. These developments should increase demand response but not to the extent the SO will be able to rely on response in the circumstances described above.

Our proposed winter peak product is an **ancillary service** available to correct for a generation shortfall following the issue of a **low residual** CAN, and where the **low residual** condition remains after any changes to market bids and offers in response to the CAN, but before a GEN is issued in relation to the WPP activation period. The response mechanism in the Winter Peak Product would comprise 1 or more of the following:

(a) **demand curtailment providers**

(b) **generation**

(c) **batteries** and other innovative technology that can meet the technical requirements

Attributes, definition and purpose of the Winter Peak ancillary service product

The table below sets out the high level attributes of the proposed winter peak ancillary services product.

Attribute	***Parameters***
Program Term	One winter, based on an urgent Code change
Resource availability	A participating resource will need to be available for the period from 1 April to 31 October, between 7 am and 10 pm. (Security Standards Assumptions Document) Note, this assumption needs to be tested. It may be the case that offers into this service are priced on the basis that they can opt out under particular circumstances but obviously that could undermine the very purpose of the product. By implication product acquired for this purpose would not be available for other duties unless it had been accepted with opt out provisions at the outset. Also, the start and end dates for winter could be tailored for this purpose only
Event trigger	Where a low residual CAN has been issued that identifies a generation shortfall, and where the low residual condition remains after any changes to market bids and offers in response to the CAN, but before a GEN is issued in relation to the WPP activation period. (The SO's internal

	standard for a "low residual" currently is a generation residual < 200MW. Analysis shows this is the point where it needs to act in order for it to meet its PPOs. This is not defined in the Policy Statement.)
Advance notice	< 8 hours
Location	Location(s) to be clearly stated and will be taken into account at the point of activation
Activation duration	1-3 hours
Event limits	Suppliers may place limits on repeat use and this would be reflected in their pricing.
Technology	Generation or demand curtailment including aggregated offerings. Demand can be of three types – aggregate demand at a conforming GXP, or a single or number of commercial/industrial loads each with individual metering points each of which can be a 24 hour load or a daytime load.
Baseline	Defined counterfactual - The baseline against which the increase in injection or decrease in consumption is assessed is given in the table below.
Payments	1. An availability payment that would explicitly rule out the service participating in other parts of the market during winter; and 2. a performance or 'activation' payment to retain an incentive to be available. For the case of a generator, the generator would not be paid the energy price for a period in which it was called on to generate.
Compliance	• Penalties for non performance • Recognition of the value of participant to not comply c.f. consequence to public • Monitoring for gaming – Transpower may audit the compliance of any WPP provider that has, prima facie, altered its generation or demand after the issue of a generation residual CAN in such a way that has a greater nominal response but a lower net response.

Some initial Code drafting

We set out below example Code drafting required to give effect to the winter peak product. To explain our approach:

- The purpose of the winter peak product is to enable the System Operator to maintain the residual during the winter period when the System Operator anticipates the system is likely to be tight. Our proposed Code drafting therefore introduces a new defined ancillary service and explicitly defines "generation residual" for purposes of the Code.

- As with other ancillary services, we anticipate the details of the product, including how it is procured and activated, would be defined in the policy statement and procurement plan (we have developed the detail in proposed additions to the procurement plan below).
- We have not proposed any changes to Part 7 because the System Operator's principal performance obligations as currently defined (specifically the obligation to maintain frequency) provide a sufficient basis for the winter peak product.
- The winter peak product is intended to operate along the same lines as frequency keeping i.e. not integrated in the market solution but integrated operationally analogous to frequency keeping. We therefore propose the costs of the service would be allocated to purchasers in the same manner as frequency keeping and have suggested amendments to Part 8 accordingly. The allocable cost of the winter peak product could include both an availability payment and an activation fee, but we have not suggested any changes to the definition of "availability cost" because all the contract payments would be allocated to purchasers (as opposed to the method of allocating availability costs for instantaneous reserve).
- Because the product is operationally integrated but not integrated into the market solution, we have not proposed any amendments to Part 13. An integrated solution would be ideal but there is a trade-off between developing an integrated product and getting a product operationalised by winter 2023. As explained above, it may be appropriate to provide for an administered price for the period the product is activated, but we have not attempted to produce drafting to address that at this stage.
- Minor consequential changes are required to Schedule 8.3, Technical Code B, to ensure that load dedicated to the winter peak product is properly accounted for. But otherwise we have not proposed broader changes.
- We understand the attraction of having services procured through this ancillary service product brought into the market via the Dispatch Notification market product but have not developed that avenue. Once there is full engagement between the Authority and industry this approach should be worked through.

Amendments to Part 1
Amend the definition of ancillary service as follows:

> **ancillary service** means **black start**, **over frequency reserve**, **frequency keeping**, **instantaneous reserve** ~~or~~, **voltage support** or **winter peak service**

Insert the following definitions:

> **generation residual** means the difference between the sum of **offers** and the expected profile of **demand** for a **trading period** as determined by the **system operator**, taking account of limits on the availability of **generation** as further described in the policy statement

> **winter peak service** means an **ancillary service** available for activation between 1 April and 31 October each year that maintains the **generation residual** at or above the level specified in the [**policy statement / procurement plan]**

Amendments to Part 8
Insert the following after clause 8.58:

> **8.58A Winter peak service costs are allocated to purchasers**

The **allocable cost** of **winter peak services** must be paid by **purchasers** to the **system operator** in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula:

$$Share_{PURx} = \frac{Fc * \max(0, \Sigma_t (Offtake_{PURxt} - E^{WP}_{PURxt}))}{\Sigma x \max(0, \Sigma_t (Offtake_{PURxt} - E^{WP}_{PURxt}))}$$

where

$Share_{PURx}$	is **purchaser** x's share of **allocable cost** in relation to **winter peak services**
Fc	is the **allocable cost** of **winter peak services** in the **billing period**
$Offtake_{PURxt}$	is the total **reconciled quantity** in **kWh** for **purchaser** x across all **grid exit points** in **trading period** t in the **billing period**
E^{WP}_{PURxt}	is the quantity of any **winter peak services** provided under any **alternative ancillary service arrangement** for **winter peak services** authorised by the **system operator** for **purchaser** x in **trading period** t.

Amend paragraphs 7(7) and (17) of Sch 8.3, Technical Code B as follows:

(7) To avoid doubt, the **demand** calculated to comprise **automatic under-frequency load shedding** blocks must be net of any **interruptible load** and **demand** attributable to **winter peak services** procured by the **system operator**.

…

(17) The **system operator**, each **connected asset owner**, each **grid owner** and each relevant **retailer** must, to the extent reasonably practicable, co-operate to ensure that any **interruptible load** and **winter peak services** contracted by the **system operator** that could affect the size of an **automatic under-frequency load shedding** block is identified to assist the **connected asset owner** or the **grid owner** to meet its obligations in subclauses (1) to (9).

Definitions required for the winter peak product in the procurement plan

The following definitions are proposed for the addition of the winter peak product in the procurement plan:

activation period – means the period during which there is a **generation residual** and where the scheduled **winter peak product** providers have been notified under clause A20 that they are to provide the services under clause B88.

advance notice – means the time before which the **system operator** must notify the **ancillary service agent** before the winter peak product can be activated.

availability and as required activation – means, for the **winter peak product**, the services defined under clause B88 will be available for the period from 1 April to 31 October, between 7 am and 10 pm; and may be activated as described in clauses A18 to A20.

Purpose of ancillary services the System Operator may purchase

The Procurement plan sets out the principles in making net purchase quantity assessments for ancillary services including the requirements of the SO to meet its PPOs. It states the ancillary services the SO may purchase from ancillary service agents and the purpose of each of these. For each ancillary service a purpose is provided. The purpose of the winter peak product would be along the following lines:

The purpose of the **winter peak product** is to restore the **residual** following the issue of a low residual CAN, and where the **low residual** condition remains after any changes to market bids and offers in response to the CAN, but before a GEN is issued in relation to the WPP activation period. The heightened risk comes from the prospect of the **residual** becoming inadequate as a result of the inherent inaccuracies between the modelled and actual system conditions i.e. the risk of a sudden rise in system demand and/or sudden declines in intermittent generation. The objective is to reduce the prospect of a grid emergency event on winter peaks.

Assessment methodology for winter peak product (Procurement Plan page 8)

An assessment methodology would follow along similar lines to the Frequency Keeping assessment methodology in the Procurement Plan. The proposed winter peak product provisions are below:

39A. Subject to paragraphs 27 and 28, all parties that can offer **winter peak product** compliant with the **system operator's** technical requirements and the **Code** and who are prepared to enter into an **ancillary service** procurement contract with the **system operator** to provide **winter peak product** on an **availability and as required activation** basis may be contracted by the **system operator** for provision of **winter peak product**. Each such **ancillary service** procurement contract is a contract to provide **winter peak product** for the purposes of clause 13.82(5)(a) of the **Code**.

39B. Parties who wish to provide **winter peak product** are subject to a pre-contract technical review. The **system operator** must be satisfied with the outcome of the technical review before entering into an **ancillary service** procurement contract with that party for **winter peak product**. Without limitation, the scope of the technical review may include a review of:

39.1B approved metering that can explicitly identify the response of plant offered for **winter peak product** and at the GXP/GIP where the response is located; and

39.2B the nature of the offered plant and that it can be discretionarily identified and controlled.

39C. The **system operator** must regularly assess the net purchase quantity of **winter peak product** in accordance with the processes set out in paragraphs B94 to B96.

39D. The **system operator** must use reasonable endeavours:

39.1D to have sufficient **ancillary service** procurement contracts with providers of **winter peak product** to cover a range of **notification periods**; and

39.2D to have sufficient providers to cover xxx MW of **winter peak product** allowing for up to two **winter peak product** providers to be unavailable, i.e. N-2.

Basis for procuring ancillary services (Procurement Plan page 16: Appendix A Bases for procuring ancillary services)

A basis for procuring ancillary services would follow along similar lines to the Frequency Keeping assessment methodology in the Procurement Plan. The proposed winter peak product provisions are below:

Winter peak product

A16. The **system operator** must:

A16.1 procure **winter peak product** on an **availability and activation basis**; and

A16.2 procure one or more **winter peak product providers**.

A17. The **system operator** may pay an availability payment and an activation fee for **winter peak product** provision[25].

[25] The activation fee could be dropped and only the availability fee be used.

A18. The **system operator** will first notify the market by customer advice notice of a **generation residual** with the **generation residual** and advise the market that the **winter peak product** will be activated. For the avoidance of doubt the **system operator** may notify the market of a potential **generation residual** without activating the **winter peak product**.
A19. The **system operator** will rank the tendered offers into a merit order (taking each generator's availability payment and activation fees into account)before the **winter peak product** is required. If two tenders have the equivalent fees then preference will be given first to the shortest **advance notice**. If the **winter peak product** is activated the **system operator** will select the provider from the merit order until sufficient **winter peak product** is scheduled to make up the **generation residual**.[26]
A20. The **system operator** will then notify each selected provider for the **winter peak product** for the **activation period** that they have been scheduled and must respond.[27]

Key technical requirements for ancillary services (Procurement Plan page 18: Appendix B – Key technical requirements for ancillary services)

Key technical requirements would follow along similar lines to the Frequency Keeping technical requirements in the Procurement Plan. The proposed technical requirements for winter peak product are:

Performance requirements and technical specifications for winter peak product

B87. The services provided for the winter peak product must be additional to normal operation, which means that for reasons including uncertainty, economics, transaction costs, inconvenience, or similar, would not normally respond to, nor participate in, the wholesale electricity market.
B88. The ancillary service agent must ensure that it provides such **winter peak product** services by:

- Ensuring the **winter peak product** volumes are not offered into the energy market, except as provided for under the **winter peak product** arrangement, or into any other ancillary service.
- After the issue of a **customer advice notice** warning of a **generation residual** make reasonable endeavours to not increase demand, in the case of a demand response provider, and to not decrease generation, in the case of a generation provider, before the potential **winter peak product activation period**. Except that a demand response provider that controls a proportion of demand of retail customers and has no other direct influence on the demand preferences of those customers, and otherwise meets the additionality requirements of B87, does not need to meet this requirement.
- When the **ancillary service agent** is notified that the **winter peak product** provider has been scheduled to respond to the **winter peak product activation period**, that the **winter peak product** provider makes best endeavours to reduce demand, for demand response, or increase generation, for generation response, according to their contracted volumes to a minimum of xx MW during the **activation period**.[28]
- Maintain metering, and provide to the **system operator** metering data as soon as practicable after responding to an **activation period**, that demonstrates the performance of the **winter peak product** provider from the point that a first **customer advice notice** is issued warning

[26] If there is no activation fee then the merit order can be ranked first by advanced notice, then by descending volume.
[27] If the winter peak product is pursued the best way of integrating the product into the market and dispatch processes will need to be investigated further.
[28] The winter peak product will need a de minimis to balance availability with operational practicality. A suitable de minimis can be chosen after further development of the market and dispatch processes.

of a **generation residual** to the end of the **activation period**. The metering data must clearly designate the GXP/GIP to which the **winter peak product** ultimately connects to the **grid**.

- Make reasonable endeavours to cooperate with the **system operator**, or duly appointed agent, to audit the **winter peak product** provider's performance when required.

Winter peak product unavailable

B89. If, having made reasonable endeavours to ensure that the **winter peak product** is available, the **winter peak product** provider is unable to make the service available, the **ancillary services agent** must notify the **system operator** as soon as practicable:

- That the contracted **winter peak product** service is unavailable;
- The expected time that the **winter peak product** will be made available; and
- The reason the **winter peak product** is unavailable.

B90. The **ancillary service agent** must notify the **system operator** of any revisions to the expected time that the **winter peak product** will be made available as soon as practicable.

B91. The **ancillary service agent** must notify the **system operator** when the **winter peak product** is available as soon as practicable.

B92. If the **winter peak product**, or a portion of the **ancillary service agent**'s **winter peak product**, is unavailable more than once, then the system operator may terminate the **ancillary service** contract or reduce the contract volume by the proportion that has been unavailable.

Monitoring requirements for winter peak product

B93. The **ancillary service agent** must use best endeavours to monitor the performance of the **winter peak product** provider during the **activation period** and notify the **system operator** of any underperformance as soon as practicable.

B94. The **ancillary service agent** must review the metering data described under B88 and, with the data, notify the **system operator** of any prima facie non-compliance with the requirements of B88. The **ancillary service agent** may also provide explanations for any prima facie non-compliance with B88.

Special testing and compliance requirements for winter peak product

B95. The **ancillary service agent** will submit, prior to the **winter peak product** being scheduled for an **activation period**, an example of the metering data required under B88. The **ancillary service agent** must make any reasonable changes required by the **system operator** to the format and/or the communication of the data but only to meet the requirements of B88.

B96. If the metering data required under B88 indicates a prima facie non-compliance of B88 then the **system operator**, or duly appointed agent, may audit the performance of the **winter peak product** for that **activation period** where prima facie non-compliance has occurred. Such audit may include:

- Exploring the reasons for any change in demand or generation from the point of a first **customer advice notice** of **generation residual** to the end of the **activation period**;
- Exploring the reasons for any shortfall in meeting the contracted **winter peak product** service; and
- Acting reasonably, determining whether the **winter peak product** response was genuinely additional to the normal operation of the **winter peak product** providers facilities.

B97. If a winter peak product provider has, on a reasonable assessment of the metering data provided under B88, met the requirements of B88 they may not be audited.