Investigation into electricity supply interruptions of 9 August 2021

MINISTRY OF BUSINESS,
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Executive summary

More than 34,000 households had their power turned off on the evening of 9 August, at the instruction of the New Zealand electricity system operator. It was an unusually cold evening which exacerbated the disruption, and it was dinner time. The national demand for electricity reached a new record that evening. It was an emergency.

At the time of the emergency there was no shortage of immediately available fuel – stored water, gas, coal or distillate – there was no large unplanned outage of generation capacity, and there was no significant transmission constraint. It is the first time an event of this nature has occurred since the electricity market began in 1996.

Our findings are summarised as:

1. We find that forced disconnection of household electricity was entirely avoidable. We find that the demand side had enough discretionary load to maintain the system, but that the system operator had inadequate visibility or up to date awareness of that resource. Turning off any householder's electricity, apart from their hot water cylinder, simply need not have happened. Ensuring that the system operator has accurate real time awareness of the size of each electricity distribution businesses' discretionary load is a central recommendation.

2. Importantly, we make the finding that no household need have suffered a power cut even if the system operator had not deployed the demand allocation notice. We find that there was no need to issue that notice, and that the system operator did so in order to further honour an equity rule embedded in the electricity code.[1] We find that rule to be ill-conceived, and in need of prompt revision.

3. The demand allocation notice was remarkably faulty. It required electricity distribution businesses (EDBs) to limit their load illogically. Its issuance caused considerable confusion. Transpower apologised in the days that followed. Trust between EDBs and Transpower has been damaged and will need to be restored.

4. We nonetheless find that the system operator staff acted capably and professionally during a challenging evening. They got us through, notwithstanding inadequate information and a faulty allocation tool. Their skill and commitment avoided the next stage of system defence, known as Automatic Under Frequency Load Shedding (AUFLS), which would have seen 16 per cent of New Zealand's electricity load shed, automatically.

5. EDBs were also for the most part very responsive and engaged throughout the evening. Generators maximised their output where practicable. There was a lot of cooperation and goodwill evident throughout the system, and throughout the event, though we identify a touch of complacency too.

[1] The Electricity Industry Participation Code 2010.

6. Transpower was criticised for inaccurately under-forecasting what turned out to be a record load. We do not support that conclusion, noting that competing forecasters were even less accurate. Nor do we place any importance on 9 August being a new record level of demand; it was the second such record this winter. We do however propose a rule change regarding wind energy estimation.

7. We investigated whether Genesis' third Rankine at Huntly or Contact's Taranaki Combined Cycle plant should have run. Claims of an undesirable trading situation and Code breaches have been lodged, and will be investigated by the Electricity Authority (EA). That scrutiny should be untainted by any detailed findings from us.

8. Accordingly, we have constrained our observations; forecast prices seemed to provide insufficient incentive to restart either plant. Some statements from generators immediately afterward were unhelpful. In coming years slow-start thermal plants will exit the system altogether.

9. We have examined planned generation outages and find nothing exceptional.

10. Some generation plant – Tokaanu and Waipipi – sharply reduced output at crucial times during the evening. Though that was an unusual coincidence, and had a material effect, we do not find the level of failure exceptional.

11. We find that 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.

12. We find that while the market has matured steadily over 25 years, it has not yet matured sufficiently or with sufficient alacrity, though we are pleased to acknowledge the change to real time pricing in the market a year from now. Of all the market making or deepening options, we think it is time to revisit a cap market to support risk management.

13. Our review of the demand side was fruitful. Our first finding is our most important. There is significant opportunity to harness the discretionary load under ripple control, which is a long-standing demand side innovation, now at risk of decay. There is also growing need to harness new demand side opportunities – electric vehicles (EV), smart appliances etc.

14. We sense the demand side will shortly develop as a more important, accessible, digitised player, along with battery technology, when it comes to the increasingly important task of shifting load from peak to off-peak. We have some suggestions, principally around one or more 'multi-hour shortfall' products. We note a very varied contribution to demand side activity from large directly connected users, and recommend how that too might be addressed.

15. There is some urgency in progressing these things. The likely changes to transmission pricing will reduce the value of ripple control to EDBs, and therefore reduce the case for continued investment. We envisage ripple control and replacement technologies being at the heart of a transition to a richer demand side participation in the market over the next decade. Improved efficiency and improved security are both possible if done innovatively.

16. A widely held view is that the nature and standard of communication in the system is neither modern nor responsive. In particular, Transpower has room for improvement. We acknowledge that improved communication was reportedly very evident in a grid emergency event the following week. Elsewhere in the system, the ownership of customer relationships is contested under conditions of stress. Other analyses of some of these issues have already been made public. We endorse findings to date, and offer some additional ones.

17. Medically dependent customers are a sensitive issue among industry participants, especially retailers. Because all households suffer unplanned electricity outages, the most important thing for a medically dependent customer is a back-up plan, developed with their clinician. The most useful piece of information for a medically dependent customer, and for everyone, is the likely length of the outage. That was mostly unavailable on the night of 9 August.

18. The EA must review and strengthen its oversight of the system operator, and by implication Transpower. We find that self-assessment, whilst informative and useful, is inadequate. A regulator and a statutory monopoly have an unusual relationship, which must be determinedly developed at more than one level. Thus, Transpower must both be challenged to be a fully compliant and responsive player, and also be supported to continue innovation and leadership in our globally unique system.

19. We asked whether our system's security settings are appropriate or whether they should be strengthened. The context includes the greater electrification of the economy, increased reliance on a continuous electricity supply, more adverse effects from climate change, and more intermittency occasioned from a transition away from fossil fuelled thermal generation towards new renewables. This question requires more analysis than we can command. What we can do is reiterate a key finding of our review, namely, that the market requires much greater demand side participation. We believe that this will be essential if goals of greater electrification and decarbonisation are to be achieved.

20. There is room for improvement in standard setting for appliance monitoring and control. Standards should ensure there is the ability for meters or phones to communicate with appliances, or EVs. We consider that both the EA and the Ministry of Business, Innovation and Employment (MBIE) have a role in proactively identifying opportunities where standard setting would be in the public interest.

21. The future will be characterised by reducing marginal costs for new generation, especially solar, contrary to the inexorably increasing marginal costs of recent

decades. Rising social and political demands to progress decarbonising the economy will dominate. Various digital technologies will enable innovation, though only if the regulatory environment is conducive and timely. Accordingly, the considerable policy work already underway within MBIE and the EA assumes significant importance.

22. We have made a number of recommendations to address these findings. These are set out in each section of this report and collated for ease of reference in Annex G.

1 Context

This investigation was commissioned by the Minster of Energy and Resources[2] and commenced on 19 August 2021. It has been led by Pete Hodgson with specialist technical advice from Erik Westergaard and secretariat support from MBIE.

The purpose of this investigation was to:

- understand the causes of power supply interruptions on the evening of 9 August 2021, when more than 34,000 consumers lost power in the evening following a direction from the system operator to curtail national demand, and
- learn lessons from the event to identify and recommend improvements to ensure similar circumstances are better managed in future.

The full terms of reference for this investigation are in Annex A.

We have drawn on information and insights from reviews being carried out by Transpower and the Electricity Authority (EA):

- Transpower has carried out an independent review of its performance as the system operator, and two reports were published on 12 October 2021. Summaries of the two reports are available in Annexes D and E.
- the EA is conducting a review under section 16 of the Electricity Industry Act into how the electricity system performed.

The EA's review has been split into two phases – the first phase sought immediate assurance that any systemic and process issues that led to the power cuts have been corrected. The findings and recommendations of phase one were released on 10 September 2021 and Transpower responded on 24 September 2021, and the executive summary is available in Annex F. Phase two of the EA's review has a broader scope and will look at all aspects of the industry response.

Our investigation is not to determine any breach of the Electricity Industry Participation Code 2010 (the Code) or other laws, address methods to reduce electricity demand or to encourage generation investment, or consider ownership or institutional governance arrangements in the sector.

[2] In a ministerial statement in the House of Representatives on 10 August 2021.

1.1 Circumstances that provide useful context for the events of 9 August

New Zealand has experienced over ten years of relatively flat demand growth, both in terms of annual electricity consumption and peak demand. Figures 1 and 2 below illustrate this.[3] The instantaneous peak demand of 7,157 MW on 9 August set a new record.[4]

We had just emerged from a "dry year", where a prolonged period of relatively low inflows meant that storage in key hydro-electric lakes was below average.

This dry year was coupled with continued constraints on the supply of gas available for electricity generation, and both contributed to very high wholesale electricity prices. In response to this situation:

- Genesis Energy had been running its Rankine units at Huntly on coal, and had brought back a (earlier mothballed) third Rankine unit to help meet winter demand.
- Contact Energy had been running its Taranaki Combined Cycle (TCC) gas plant to help meet winter demand.

By 9 August 2021, national hydro storage levels were at 101 per cent of average for the time of year as inflows had improved, and there was no physical constraint on the supply of gas.

Figure 1: New Zealand electricity peak demand 1997-2021

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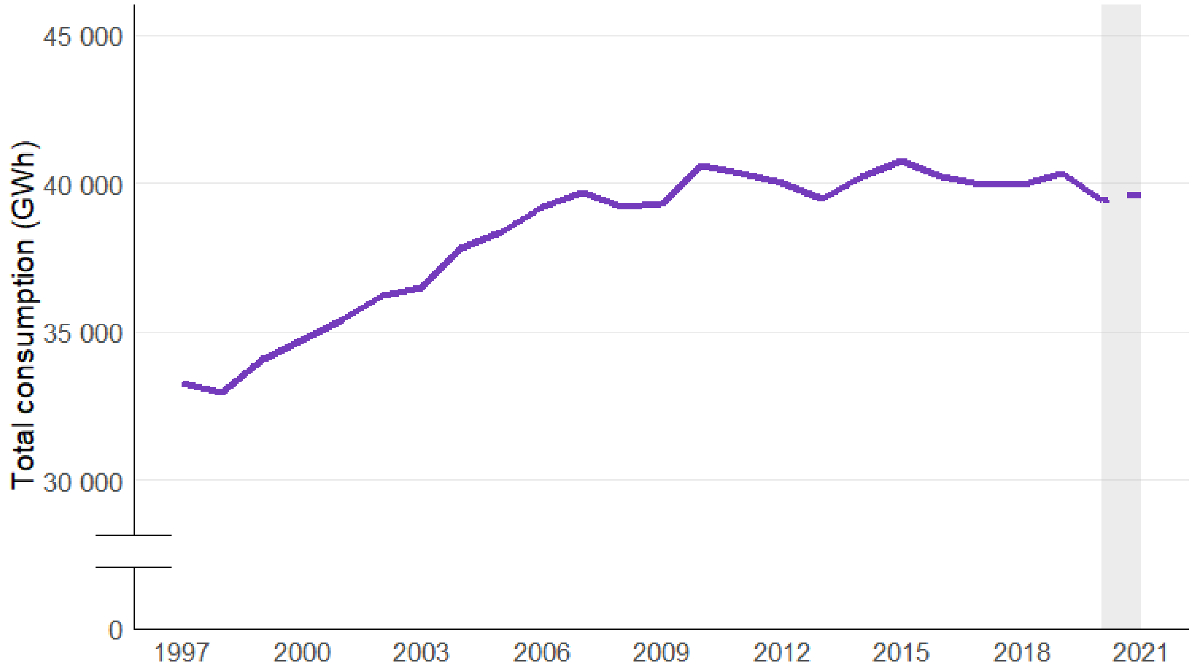
[3] Source: MBIE, New Zealand Energy Dashboard, with the addition of an estimated consumption for 2021 derived by scaling grid demand in October to December 2020 to account for differences in demand between 2020 and 2021 due to a range of factors including restrictions on activities and movement in different parts of the country in the response to the COVID-19 pandemic and the weather.

[4] Note that the peak demand in Figure 1 is *grid export* only data (averaged over half hour trading periods). Total "average demand" was 7,083 MW during the peak half hour trading period on 9 August, and the peak instantaneous demand on 9 August was 7,157 MW.

Figure 2: New Zealand electricity consumption 1997-2021



1.2 Government policy that provides context for our findings and recommendations

The Government has an aspirational goal of reaching 100 per cent renewable electricity by 2030. This goal is part of the transition to a net-zero carbon economy by 2050, and is supported by a renewable energy work programme.

This includes work on:

- Measures to reduce our reliance on fossil fuels for electricity generation.
- Addressing our dry year storage issues through the New Zealand Battery Project.
- Facilitating renewable energy through resource management legislation and national direction.

2 Overview of 9 August and timeline

9 August 2021 was one of the coldest nights of the year – New Zealand experienced a new record national demand for electricity, but more than 34,000 households were left without power – some for more than two hours.

Leading up to the outages, multiple notices were issued from the system operator and a series of events unfolded as set out in the below timeline.

We acknowledge that as events unfolded, Transpower, as the system operator, took immediate steps to prevent the possibility of a more widespread and additional outages occurring.

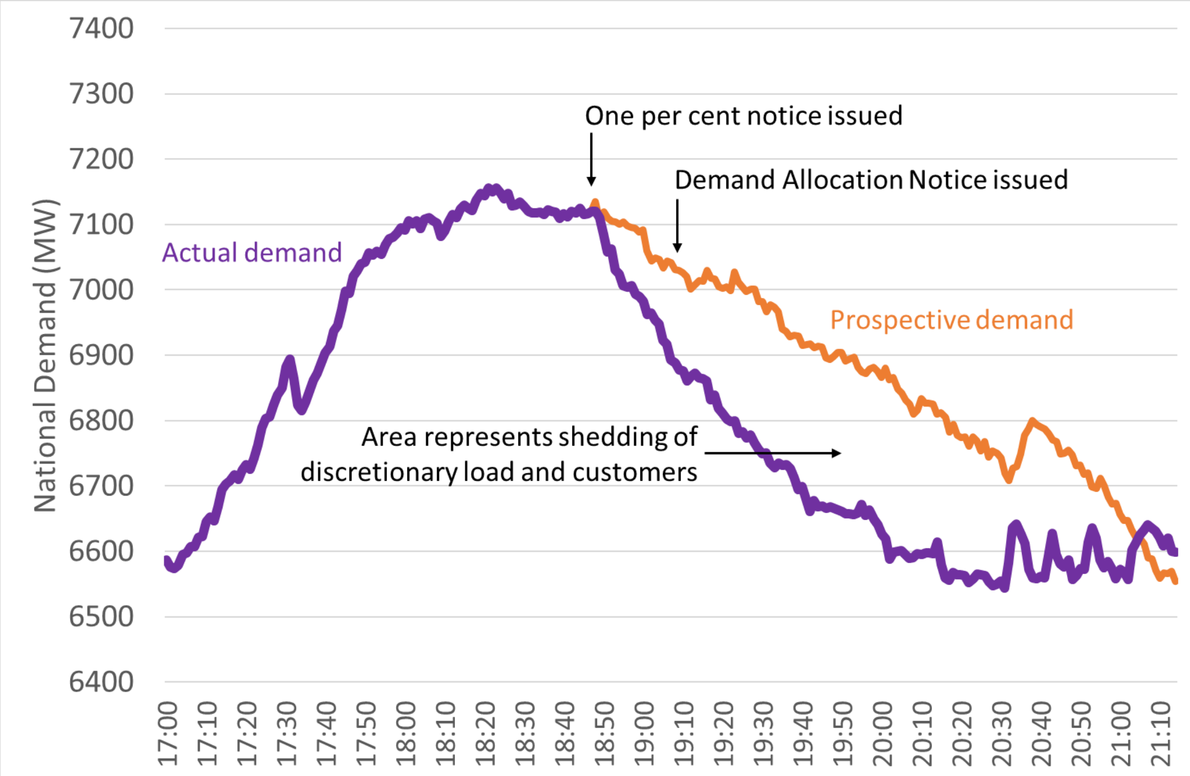
Time	Event
Up to 06:00	Peak demand forecasts range between 7160 MW and 7180 MW
06:42	Customer Advice Notice (CAN) issued for forecast low “residual” (difference between generation available and demand) between 17:30 and 20:00
08:30	Increased generation offers return the forecast residual to over 200 MW
10:30-12.30	Forecasting schedules shift from no generation deficit to a deficit of up to 149.6 MW for the period between 18:00 and 20:00
13:02	Warning Notice (WRN) issued telling market participants that there is a risk of insufficient generation and reserve (energy) offers between 17:30 and 20:30 Participants asked to increase energy offers and decrease demand, and told that if there was an insufficient response, the system operator would manage demand and restore power system security
17:00	Forecasting schedules show a reserve deficit of up to 31 MW between 18:00 and 19:00, largely driven by a drop in wind offers and an increase in demand
17:10	Grid Emergency Notice (GEN) issued advising of NZwide emergency Forecasts insufficient generation offers between 18:00 and 19:00, and asks for increased energy offers and demand reductions
17:10-18:45	Some Electricity Distribution Businesses (EDBs) respond by shedding some or all discretionary load available, and there is a visible drop in demand Generation is lost from Tokaanu due to a lake weed blockage, and there is a significant drop in wind generation due to falling wind speeds The system starts to use generation from the reserves market Demand hits 7,157 MW at 18:23 – the highest instantaneous peak ever
18:47	GEN revision issued extending the emergency out to 20:00 All network companies are requested to reduce load by one per cent
By 18:53	One per cent load reduction is achieved by some EDBs shedding discretionary load, and some disconnecting customers (where no discretionary load left) By 19:08, load has reduced by three per cent

Time	Event
19:09	GEN revision issued to provide network companies load control limits that were set out in an incorrect Demand Allocation Notice (DAN) Eight EDBs were asked to reduce load further – five followed the DAN, two of which disconnected additional customers
19:30	Transpower Communications team advised that customers have been disconnected
19:41	Minister of Energy and Resources’ office receives an email from Transpower advising of the situation, but with no follow-up with a more direct means of communication
20:20	GEN revision issued extended emergency to 21:00 Advises network companies to increase their current load by 5 per cent
20:24-20:56	First question answered and public statement made on Transpower’s Facebook The Minister of Energy and Resources is made aware of the situation following a call from the media to her Press Secretary
21:01	GEN revision issued ending grid emergency Advises all participants that they can restore all load
21:15	EDBs have reconnected all customers and restored all load

Figure 3 below illustrates the impact of the events on electricity demand, with the load reductions and outages shown as the difference between actual demand and the demand that would have otherwise been met (prospective demand).[5]

[5] Data kindly provided by PBA Consulting, as per its Report: Independent Investigation of the 9 August 2021 Grid Emergency.

Figure 3: Electricity demand and response, 9 August 2021



3 Performance of the system and the system operator

We find that forced disconnection of load on the evening of 9 August was entirely avoidable – turning off any householder's electricity simply need not have happened. We further find that the demand side had enough discretionary load to maintain the system, but that the System Operator (SO) had inadequate visibility or up to date awareness of that resource.

The 'equity' provisions in the Code also contributed to this outcome.

We acknowledge that the SO needed to take urgent action to reduce demand to restore frequency. Failure to do so would have likely resulted in Automatic Under-frequency Load Shedding (AUFLS) as the next stage of system defence. This would have forced the disconnection of a significantly greater number of customers.

The Demand Allocation Notice (DAN) following the across the board one per cent notice (both issued to address the equity requirement), was remarkably faulty. It required lines companies to limit their load illogically. Its issuance caused considerable confusion. Transpower apologised in the days that followed. Trust between Electricity Distribution Businesses (EDBs) and Transpower has been damaged and will need to be restored.

3.1 The situation escalated unexpectedly and caught parties off-guard

In our interviews with generators and EDBs we repeatedly heard that despite the succession of forecasts, schedules and formal notices, there was a general expectation that this wasn't particularly out of the ordinary and the situation would be resolved as the day progressed and participants responded.

Some generation plant – particularly Tokaanu and Waipipi – sharply reduced output at crucial times during the evening. Though that was an unusual coincidence, and had a material effect, we do not find the level of failure exceptional. Bigger events can and do happen.

9 August set a new record for electricity consumption, but we place no great emphasis on that either – it was the second such record this winter.

In short, we acknowledge this event had characteristics of the 'perfect storm' but we are disinclined to dismiss it as an unfortunate one-off event. On the contrary, we believe a modern electricity system should be able to accommodate such a situation. Indeed, had the SO been more aware of demand side capacity, and had the SO felt able to overlook the equity rule, 9 August would have been an uneventful evening.

3.2 The system operator avoided much more widespread outages

We wish to acknowledge the skills and the commitment of the SO and Transpower staff who had a rather challenging evening and whose professional approach is the reason a bad situation did not become worse. They acted professionally and effectively to achieve their primary aim – to avoid much more widespread outages, and possible cascade failure.

We have been given an insight into the evening via telephone transcripts of conversations that were internal to Transpower and the SO, or were between Transpower or the SO and various EDBs. There were dozens of such conversations, typically short, respectful and to the point. Nonetheless as the evening progressed one could discern growing confusion, and it is hard not to feel sympathy for those trying to hold it all together.

Top of mind for the SO staff was maintaining the 50 Hz frequency of the electricity system. If the frequency slows beneath a particular point the electricity system is in danger of a cascade failure, where the system needs to be restarted afresh. This is called a black start. This event has occurred in other jurisdictions in modern times but not in New Zealand.

On the night the SO needed to take urgent action to reduce demand to restore frequency. Failure to do so would result in the AUFLS system tripping as the next stage of system defence – 16 per cent of New Zealand's electricity load would have been shed automatically, followed by another 16 per cent if frequency continued to drop.

Avoiding an AUFLS event, or worse – a cascade failure followed by prolonged outages and restoration – was the primary aim for the SO staff.

Others played important roles in averting these dire outcomes, particularly the EDBs. Generators maximised their output where practicable. Some large users were also very responsive. It is important to emphasise and acknowledge that there was a lot of cooperation and goodwill evident.

3.3 The equity rule in the Code is flawed

Having established the need for about 71 MW of demand reduction, the SO could have just rung the biggest EDBs and asked for all their remaining hot water to be turned off, then continued down the EDB list until enough load had come off the system. But that would have been inequitable and against the Code requirements.

The SO was guided by the equity rule in the Code when, at 18:47, a Generation Emergency Notice was issued asking for each EDB to reduce load by one per cent. The SO was again guided by the equity rule when, at 19:09, a DAN was issued which gave each EDB its permitted maximum load, expressed in MW. As it happens the DAN was faulty.

That the equity rule was on the minds of the SO staff is apparent from the transcripts. In any case it should be no surprise – rules are there to be complied with.

Specifically, rule 7 in Schedule 8.3, Technical Code B of the Code states:

> *"To the extent practicable, the system operator must use reasonable endeavours when instructing the electrical disconnection of demand to ensure equity between connected asset owners."*

In practice that means that the SO ought not ask a particular EDB to do more than its fair share. However, during the grid emergency some EDBs had spare discretionary load available to offer (typically hot water cylinders that could be turned off using ripple control), and whereas others had none.

The SO didn't have awareness of that unused discretionary load. Even if it had known, getting access to that capacity and using it, would have required the SO to break the equity rule.

A closer look at some detail is instructive. Needing to reduce demand to maintain frequency within the set band, the SO instructed each EDB to reduce load by one per cent, a total of 71 MW at 18:47. The one per cent was delivered in just six minutes, with some EDBs making a bigger reduction than that asked for. At 19:09, 22 minutes after the 18:47 call for a one per cent reduction, a DAN was sent out. The load reduction continued, reaching 217 MW or about three per cent after about 45 minutes.

About two per cent of this reduction was delivered by using ripple control and some other load reduction options, along with a natural easing as the evening progressed. But about 34,000 households were fully disconnected, and they contributed a further (just over) one per cent or 80 MW of that 217 MW total load reduction.

This error ridden DAN caused a good deal of confusion among the SO and EDB staff in the ensuing twenty or thirty minutes. At one point, the SO staff discovered that some EDBs could apparently increase their load, and instructed that they be rung and advised of this. The SO then found other EDBs who needed to significantly decrease their load. Third, there were others still who were given a load limit so high that they would never reach it, the most extreme example of which was New Zealand Aluminium Smelters Limited (NZAS) at Tiwai who was told its limit was approaching twice what it typically use. The error-ridden DAN is the reason why most but not all affected households were disconnected. We explore this issue further, using WEL as a case study, in the box below.

In all, the system over-responded. The original request for a one per cent load reduction soon became an actual reduction of three per cent. Generation was *reduced* in response. Whirinaki, an expensive plant, began reducing from about 19:10, and at about 20:20 one generator rang the SO, noting unhappily that they were generating about 120 MW below their capacity because the overall load had been reduced so much.

Yet, at this time thousands of households were without electricity – a wholly unacceptable situation.

We consider that the equity rule is ill-conceived and must be amended. Some EDBs were able to deploy their ripple control systems to offer more than the one per cent requested, 9 per cent in one case, others obeyed the instruction strictly and therefore had ripple control up their sleeves, whereas a third group had little or no ripple control in the first place and had to therefore contemplate disconnecting households.

The main reason for this variation is that some EDBs had already deployed their ripple control to avoid transmission costs or to reduce constraints on their own distribution networks. This is a not uncommon practice on a cold night.

When the call was made to issue the one per cent notice we believe there was a significant quantity of ripple control untapped. Based on our enquiries and information provided to the EA, we estimate the untapped potential to be 112 MW.

Some simple arithmetic makes the point afresh.

Load Reduction Achieved		217 MW
Less - Load shedding by EDBs, Household Disconnections	-	80 MW
Load Reduction delivered from Ripple Control	=	137 MW
Less Load Reduction Required/sought	-	71 MW
Excess Ripple Control Load Reduction	=	66 MW
Plus - Unused Ripple Control	+	112 MW
Total ripple control available in excess of 71 MW needed:	=	178 MW

On this basis we have concluded that forced disconnection of electricity was entirely avoidable – turning off any consumer's electricity, apart from their hot water cylinder, simply need not have happened.

In our view there is a more important equity principle that must apply first. It is that all discretionary load (such as hot water) must be disconnected before any real load (such as cooking, lighting, heating) is disconnected. That is, equity between customers must hold primacy over equity between EDBs.

Only when all discretionary load has been exhausted and actual customer demand shedding is still needed, should that be done "equitably" between EDBs.

We recommend the EA amend the Code to ensure the equity rule is deployed only when ripple control and any other type of discretionary load available has been exhausted.

3.4 The system operator needs better visibility of discretionary load

Compounding the complex situation the SO faced on the night was that it had no real time knowledge of how much discretionary load (such as hot water heating) each EDB had available to disconnect. The SO could ring and ask, and did, but there is no national real time overview of the capacity of the demand side. Therefore, they were managing a system they couldn't fully see. This strikes us as extraordinary. We recommend in section 5 that this be addressed.

WEL Networks case study

WEL Networks is a moderately large EDB based in Hamilton. On the night of 9 August it disconnected 17,751 households, more than any other EDB. Its experiences and decisions give an interesting, and dispiriting, insight.

WEL decided to activate its ripple control earlier in the afternoon than did many other EDBs. During the afternoon, the SO had issued warnings – a Warning Notice (WRN) at 13:02 and then the first Grid Emergency Notice (GEN) at 17:10 – that signalled increasing trouble, but did not include a specific numerical instruction. A GEN notice is an unusual event. WEL was among those EDBs that responded early to those signals, perhaps also motivated by a desire to avoid transmission or distribution constraints.

By 18:00 they had no hot water ripple control capacity left. All 20 MW of it had been offered to the SO in response to those increasing signals of concern. That is, all hot water was turned off.

At 18:47 the SO asked for a one per cent reduction from each EDB. Under the rules WEL had to comply. With no ripple control left, it cut power to 1,372 households.

At 19:09 the SO sent all EDBs a Demand Allocation Notice (DAN). It gave each EDB a maximum allowable load, expressed in MW. The DAN was faulty. Some EDBs, including WEL, received a maximum allowable load that was mistakenly low. Again, after questioning the DAN, WEL complied, cutting electricity to another 16,379 households, for between 32 and 72 minutes.

At this time there were several EDBs who, though they had acted as instructed, still had considerable unused ripple control capacity to offer. Had that capacity been deployed first, it would have readily averted any power cut to any household.

There is one more, much smaller, dysfunction to record. By 20:20 the emergency was passing and the SO told EDBs they could increase their loads by five per cent. Because WEL had cut electricity to so many households as a result of the faulty DAN, it was unable to restore all of them despite the five per cent increase in allowance. So, for a short period some households remained without power, whilst at that time elsewhere in New Zealand hot water cylinders were being turned back on.

3.5 Electricity Authority oversight of the system operator could be more assertive

In the aftermath of 9 August attention has focussed on Transpower and in particular its role as the SO. This is understandable but it overlooks other important players.

In this section we focus on the EA, and on its relationship with Transpower. Contracting for the SO services is a specific function of the EA under the Electricity Industry Act 2010 (see section 16(1)(h)). Transpower's role as the SO is monopoly provider of core system operation service, and is given this status in the Act (see section 8). We don't seek to disturb this arrangement, other than note that having Transpower provide the SO services is not some immutable pre-requisite to a functional electricity market.

Transpower attracts respect and appreciation for the cleverness of its staff, skills that are rare or unique in the New Zealand economy. It also attracts criticism and disapproval when it exhibits monopolistic behaviour or undue defensiveness.

So, it is a difficult relationship for the regulator, the EA, which cannot by law look elsewhere for services, and which suffers from a significant information imbalance. That is perhaps why the system relies on Transpower's self-assessment and self-monitoring to the extent that it does.

We suspect that the current arrangements are inadequate. As a case in point, the fact that the DAN existed in such a shambolic state reflects on the EA as well as Transpower. Within the mix of Code, contract, policies, procedures and established practice that defines the relationship between the EA and SO, we assume there is commentary that requires Transpower to adequately test its tools with the industry under simulated stressful conditions.

Further, we know that Transpower has not always responded to the findings of reviews of earlier events. Thus, some of the findings we and others make of Transpower are not new. They have been made before but not acted on.

We believe the EA needs to lift its performance and become a more informed, methodical and proactive monitor of this proficient, but myopic, statutory monopoly. Transpower lost a lot of stakeholder confidence on 9 August. In our view a good regulator might well have prevented or ameliorated some of the missteps of the evening.

That said, we are ourselves feeling in two minds. We believe it is in New Zealand's interests for the EA to also support Transpower as it seeks to invent or adopt new technologies toward a smarter future using a smarter grid. Transpower will be one of many players in this field, but it has to be able to act in a leading role because it is the most central player. We have a little more to say regarding the role of innovation in section 7.

For now, we observe that the EA has two roles to develop – that of a more hands on regulator and that of a more permissive one. There are other such agencies afoot from whom lessons may be learned. The recently created New Zealand Space Agency, for example, is expected to regulate and facilitate an industry simultaneously.

We recommend that the EA scrutinise its relationship with Transpower, perhaps with international input, with a view to holding Transpower more firmly to the rules and contracts that bind it. We believe the EA should specifically report its progress on this recommendation to the Minister, using its existing reporting mechanisms. We invite the EA to engage with other regulators which successfully both support and regulate their industries.

…perhaps a bit of complacency was at play too

When reviewing an event, it is neither useful nor fair to adopt the wisdom of hindsight, so we are hesitant to suggest that complacency might have been a factor in the events of 9 August.

Yet people very often spoke to us with disarming candour, and snippets of complacency laced many narratives. So, we have decided to name it as a contributing feature. We are also clear that we uncovered nothing illegal or reckless or dismaying. On the contrary, the narratives and transcripts all indicated a great deal of good will and professionalism.

Why, then, the complacency label?

First, Transpower's three level warning system evoked varying degrees of action or interest. Some EDBs acknowledged that they didn't bother reading or much responding to the first or even second level warning. True, first level warnings are not uncommon – just another email in the inbox, and pretty uninformative if you bother to open it. Some acknowledged that the second level didn't evoke much interest either. One EDB said that if Transpower wanted something they would ring.

It was commonly said that Transpower often 'cry wolf' and that there are better forecasting tools available than Transpower's. That rang hollow on the night because Transpower's forecasting was the most accurate of all.

Transpower itself had demonstrated complacency by allowing a dodgy tool – the Load Shed Restore (LSR) tool used to allocate demand so that the final demand reduction is equitably shared amongst the EDBs in the demand allocation notice – to be used without adequate testing. Elsewhere we have said that Transpower's communications must be significantly improved. They must adopt a more expansive, timely and service oriented view of their role.

As the emergency took shape there was a lot of activity between key players and it was those cool heads that stopped a bad problem becoming worse.

But other players had just gone home. Usually it was of little consequence as they operated quite small parts of the bigger picture. But even so there was a role for all players. Some were active from home; others didn't quite know what was happening until much later.

We acknowledge that an event quite like this has not happened before. And we acknowledge that the electricity industry has had a period of low load growth and therefore a relatively quiet time of it in the last decade or so. But load growth is back, and the move to renewables is afoot, which will remove slow-start thermals from the equation, just as they removed themselves on 9 August.

There is an increased risk of an event like this recurring. Complacency has no place in our future.

Section 3 recommendations

1. *We recommend that the EA amend the Code to ensure the equity rule is deployed only when ripple control and any other type of discretionary load available has been exhausted.*

2. *We recommend that the EA scrutinise its relationship with Transpower, perhaps with international input, with a view to holding Transpower more firmly to the rules and contracts that bind it. We believe the EA should report its progress on this recommendation to the Minister of Energy and Resources after six months. We invite the EA to engage with other regulators in New Zealand which successfully both support and regulate their industries.*

4 Wholesale market and supply side

In assessing the performance of the electricity market and the supply of generation on 9 August, it is important to begin with some observations.

The New Zealand Electricity Market began on 1 October 1996, 25 years ago. Over this period, it has evolved in response to periodic reviews and challenges such as dry years and events such as 9 August. We believe it remains the best model for delivering the outcomes expected from the sector. We are keen to see it improved.

Yet the electricity sector in New Zealand will need to adapt rapidly if it is going to maintain its social license to operate. If people lose trust in the market and market participants, perhaps because of pricing or reliability, then the political process may explore alternatives to the current market. Such alternatives exist and are being used in other jurisdictions.

4.1 The event was not caused by a lack of fuel

The New Zealand electricity market is considered to be energy constrained under normal conditions. This is because New Zealand is heavily dependent on the production of electricity from hydro-electric power stations, generation that requires a regular supply of fuel – water either from inflows or stored water in lakes.

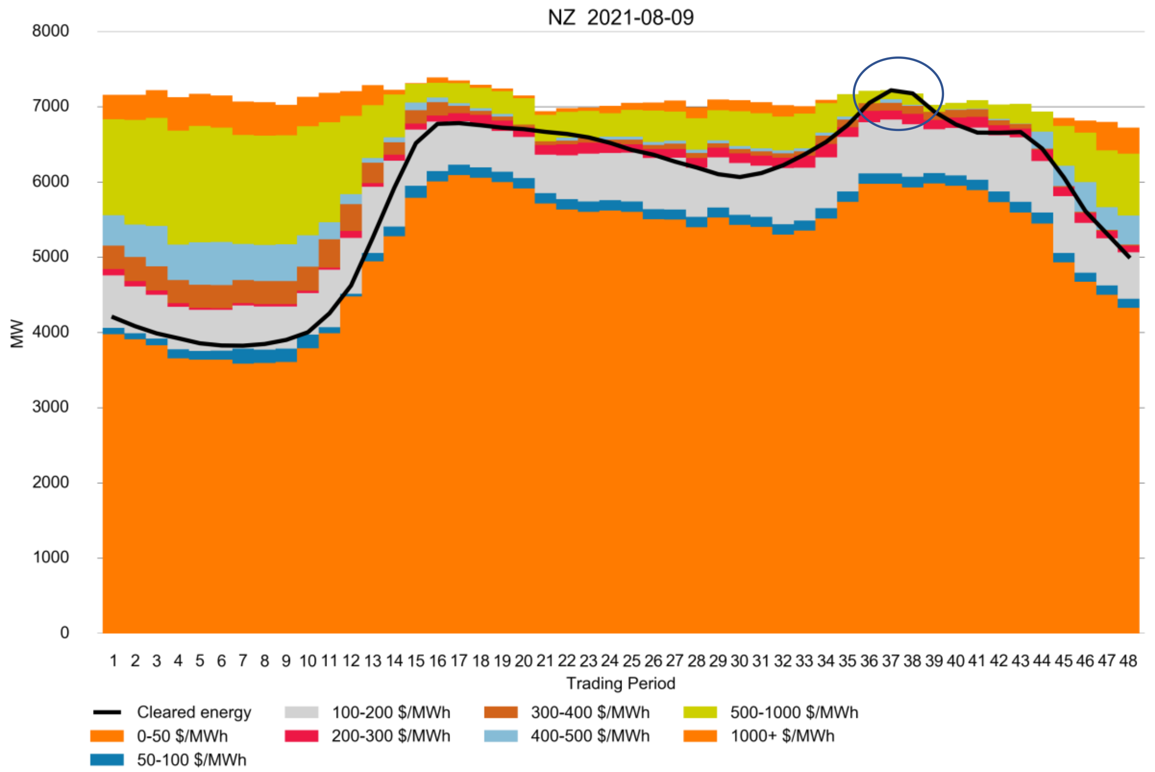
Earlier in 2021 the electricity sector was facing an energy constraint due to limited inflows to hydro storage lakes and consequently declining lake levels. In response, generators increased production from thermal power stations and raised prices signalling to consumers to reduce consumption.

On 9 August by contrast, the energy constraint had resolved and New Zealand faced a capacity constraint. There was not enough generation capacity available to meet both customer demand and the need for reserve capacity to ensure the security of the power system – the reason a grid emergency was declared by the SO.

As a consequence, prices rose to very high levels. This is shown in Figure 4 below, which reveals demand exceeding supply – the circled area.[6]

[6] Source: generation offers and cleared generation data (energy), Electricity Authority.

Figure 4: Generation offers and load profile, 9 August 2021



4.2 A lot of generation was on planned maintenance

Before commenting on the generation not available to the SO, it is important to note that the electricity market is a voluntary market, and the Code does not mandate that a generator must offer in all generating units. In clause 13.6(1)(a) of Part 13 the Code specifies:

> *"Each generator with a point of connection to the grid, and each embedded generator required by the system operator to submit an offer under clause 8.25(5), must— (a) submit to the system operator an offer for each trading period in the schedule period, under which the generator is **prepared to sell** electricity to the clearing manager; and…" (Emphasis added)*

Owners of generation therefore have flexibility under the Code about when they choose to make their plant available to generate electricity to meet customer demand. However, this is subject to other provisions of the Code, in particular Part 5 which relates to undesirable trading situations.

The first place to look at when considering why there was insufficient generation on the evening of 9 August is to consider what plant was unavailable due to planned outages.

For various reasons generation plant is taken out of service for planned maintenance. To facilitate coordination between generators and Transpower the SO runs a Planned Outage Coordination Process (POCP).

Based on our interviews with market participants and information provided by the EA, we were able to ascertain that more than 600 MW of generation capacity was unavailable on over the evening peak on 9 August due to planned outages, as set out in Table 1 below. We note that the generation capacity not in service due to planned maintenance was substantially higher than 2020, but not substantially different from 2019.

Table 1 – Comparison of Plant Capacity on Planned Outage on 9 August, 2019 – 2021[7]

	Year		
	9 August 2021	9 August 2020	9 August 2019
Plant MW on Planned Outage	602.3	286.7	592.8

The total for 2021 included a number of large generating units at the following South Island generating stations:

- Clyde – 116 MW (long term outage)
- Benmore – 90 MW (5 July to 5 November)
- Manapouri – 125 MW (19 July to 25 September), and
- Ohau A and B – 121 MW (2 to 18 August).

While it is unfortunate that these outages coincided with a new record peak demand, we note that the owners of plant have to accommodate a number of factors when planning outages. For example, expected hydro inflows, forecast demand, forecast spot energy prices, exposure to high prices, access to parts and equipment, availability of skilled personnel, nature of required maintenance, are among a myriad of factors that are taken into consideration when planning outages.

The planning for outages can take weeks to several months. Based on the above we find that there was no unusual activity with respect to maintenance outages on 9 August. Furthermore, we find that while there was significant capacity not available, 268 MW of generation capacity that was due to be taken out of service on 9 August, remained in service. This action was a response to the SO operator notices and forecast high prices.

Both TCC (385 MW) and a third Rankine unit (250 MW) were not offered into the market. This is another 635 MW of capacity, giving a total of 1237.3 MW of generation capacity not available to the SO to meet demand.

[7] Source: POCP File supplied by Electricity Authority. Please note that there are differences between the reported outages in this report and the report "*Independent Investigation of the 9 August 2021 Grid Emergency*" prepared by PBA Consulting for Transpower. A reconciliation has found that there are differences in the data sets provided to MBIE and PBA Consulting. These differences do not alter our findings.

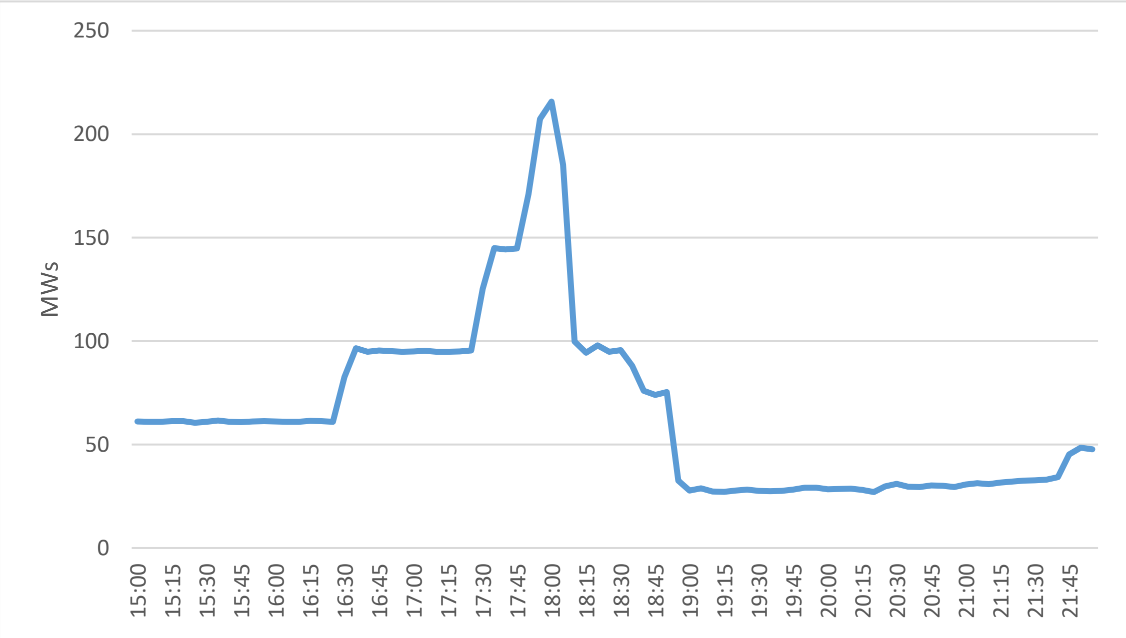
In case the question is asked, we also find that no plant was removed close to 9 August, in the face of a possible supply problem being known to the market. The latest that plant was taken out of service for maintenance was 3 August 2021.

4.3 Reduced intermittent generation was important but not exceptional

Compounding problems on 9 August was the loss of generation capacity at the Tokaanu power station due to weed clogging up the water intakes, and a drop in wind speeds reducing output from wind farms.

On 9 August, Tokaanu had been experiencing a lake weed problem for much of the day, with the prevailing wind driving the weed towards the power station. This had resulted in output being reduced earlier in the day but increasing through to 18:00 when its production peaked at 215 MW, before being dramatically reduced by 188 MW over the following hour to a low point for the day of 27 MW. Figure 5 below illustrates this.[8]

Figure 5: Tokaanu Power Station generation profile – 15:00 to 22:00, 9 August 2021



This reduction in generation coincides with the grid emergency declaration by the SO and the GEN notice issued at 18:47 by the SO for a one per cent reduction in load.

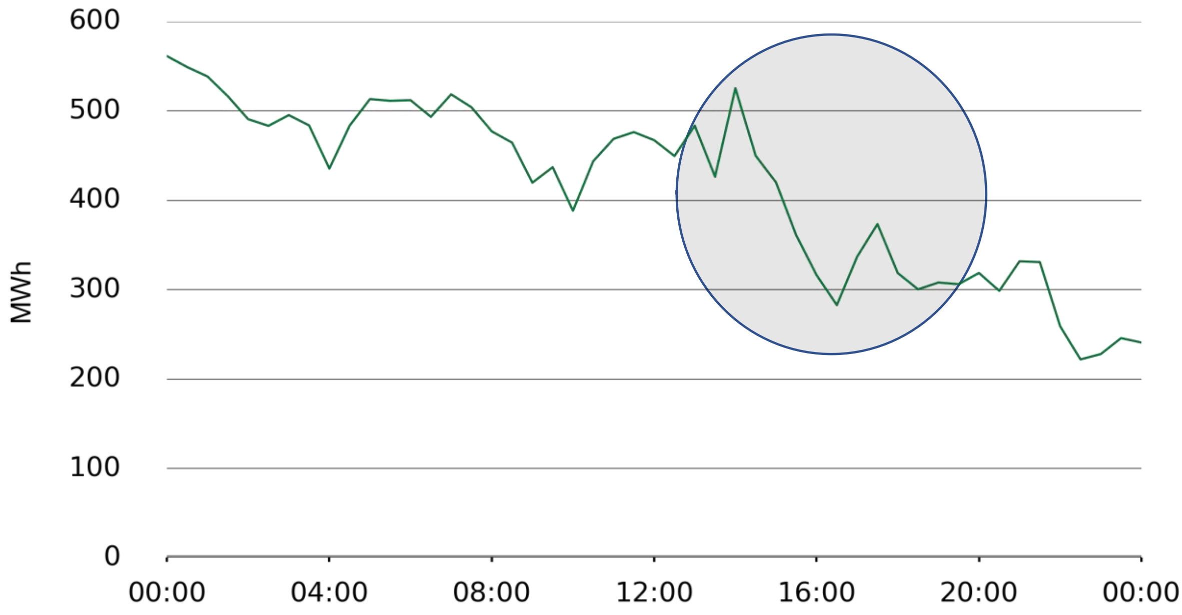
We would note the similarities of this event with a similar national grid emergency between 17:34 to 20:00 on 19 June 2006, when generation at Tokaanu was also reduced (by 200 MW) by a lake weed problem.[9]

On 9 August, the SO had received just under 500 MW of offers from wind generators by mid-afternoon. Over the evening peak, a maximum of approximately 300 MW of wind

[8] Source: cleared generation data for Tokaanu Power Station, Electricity Authority.
[9] System Operator Annual Review and Assessment, 2006/2007. www.ea.govt.nz/assets/dms-assets/1/1957SO-Annual-Review-2006-07.pdf

generation was actually being produced – 200 MW less than expected. This is shown in Figure 6 below.[10]

Figure 6: Wind generation, 9 August 2021



There is a need for better forecasting of the resource. The Code currently allows generators to use a persistence forecast in making their offers to the SO. In essence this means that the forecast generation is based on immediate past generation, irrespective of any changes in wind forecasting. This can significantly over-estimate wind generation when the wind is dropping.

In response, we recommend that the EA remove the rule allowing wind generation persistence forecasts and require all wind generators to use more accurate ways to make their offers to the SO. We note that some major generators already do this; others do not.

4.4 Spot price forecasts did not consistently signal risk of generation shortfall

Spot price forecasts for the evening of 9 August were inaccurate in hindsight, being well below the interim final prices that exceeded $10,000/MWh in several regions during two hours that evening. Earlier that day and previous days, some schedules did indicate insufficient generation, and associated high forecast prices, but not in a consistent manner.

Arguably, the price forecast inaccuracy on 9 August was simply a consequence of not anticipating the particular combination of events that occurred that day – the drop in wind generation coinciding with a significant reduction in Tokaanu generation due to weed at the time of record peak demand.

An alternative perspective is that forecast prices for 9 August were volatile, being very sensitive to small changes in demand and generation. We understand that such price

[10] Source: cleared wind generation data, Electricity Authority.

sensitivity is not unusual and has been a subject of previous investigation and analysis by the EA and its Wholesale Market Development Advisory Group.

The SO issued several CANs on 9 August, and in the days before, indicating low residual generation. These notices identified a low margin (less than 200 MW) between offered generation and forecast demand plus reserves, not an insufficiency of generation. Many participants we interviewed said it is not uncommon to see CANs advising low residual generation, and not uncommon to see high forecast prices that do not eventuate as final prices. We got the impression many participants do not take such indicators of potential generation insufficiency very seriously, because experience tells them the generation needed generally turns up on the day.

In hindsight, it might appear that one or both of the two generation units not offered on 9 August could have operated profitably, given that average prices for the day were approximately $1,230/MWh, had they been dispatched during the trading periods when prices exceeded $10,000/MWh.

However, had one such unit been offered and dispatched, it is likely that no demand curtailment would have been required and the final price would not have reached $10,000/MWh. It would instead have been set at a very much lower price.

This last point highlights a challenge faced by generators operating slow-start thermal plant with material start-up and minimum operating costs – any offer that involves starting a cold unit must be sufficiently high to recover all of its operating costs, yet sufficiently low to give some confidence the unit will actually be dispatched for sufficient time to recover those costs.

We nonetheless found remarks in the immediate aftermath by Genesis and Contact to be unfortunate. Genesis said that they had enough generation to supply their own customers and Contact said they did not run TCC to avoid spillage at Lake Hawea. Both companies must surely have known that in the New Zealand electricity market such remarks were unhelpful, and the swift and adverse reaction from others demonstrated that they were also provocative.

We do not comment on Contact's or Genesis' decision-making on and in the days before 9 August, but at face value it appears the forecast prices provided insufficient incentive for them to offer their slow start plant.

We think this situation could easily be repeated if similar circumstances were to arise in the future, particularly if wind generation remains so inaccurately forecast, as wind becomes an increasingly significant portion of the supply mix.

4.5 Prices can be very sensitive to small changes in demand

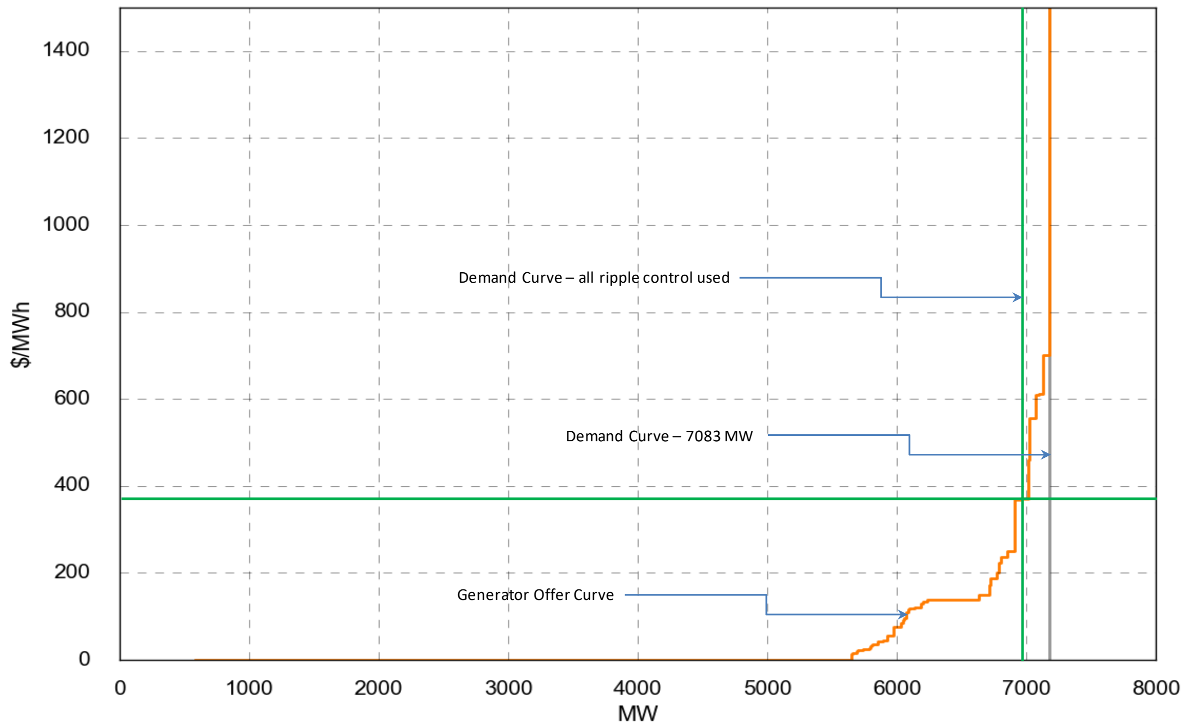
We have identified that there was 112 MW of interruptible load available but unused during the grid emergency on 9 August. If this was fully utilised, there would have been no requirement to disconnect customers during the grid emergency.

Not only would load shedding not have been required, but spot energy prices would have been very much lower. Figure 4 above shows that there was a shortage of generation capacity leading to high prices.

Another way to present this is set out in Figure 7 below.[11] It is the near vertical nature of the price curve that we wish to highlight. This abrupt lift in price, well off the scale shown here, is in part caused by the lack of maturity in the demand side of the market.

Not only does 112 MW of additional interruptible load reduce the clearing price from something like $10,000/MWh to a little under $400/MWh, but we can be sure that in a more mature demand side market there is more where that came from. It is important we uncover that potential, which we seek to in section 5.

Figure 7: Supply and demand curve for trading period commencing 18:00, 9 August 2021



4.6 The market needs better price risk management tools

Some parties we spoke with suggested that weak or ineffective competition in the wholesale market contributed to the generation insufficiency and resulting high prices for two hours on 9 August.

As noted already, the EA is investigating an alleged breach of trading conduct rules on 9 August, and it is separately reviewing wholesale market competition since mid-2018. We do not cut across the EA's work but we do have some high level observations about wholesale market competition.

[11] Source: generation offers, cleared generation, and interim price data, Electricity Authority.

Some participants, particularly independent retailers and major consumers, told us they have little ability to insure themselves effectively against the very high spot prices that can occur unpredictably, such as on 9 August. We also heard that some participants with the ability to provide such insurance (using flexible generation or demand management resources), can't easily sell it, due to an apparent lack of willing buyers.

While standardised futures are traded on the ASX Futures Exchange, these products are designed to hedge average spot prices during a period (month, quarter or year), but they are not tailored to insure the risk of very high prices lasting a few hours in a week or month ahead.

In short, New Zealand appears to lack a deep and liquid market for products to help wholesale buyers efficiently manage their exposure to very high spot prices at times of low residual generation. The inadequacy of risk management markets may limit market entry or expansion, especially by participants that don't already have physical resources to help manage those risks.

The EA has previously advocated for 'financial cap products' to be traded on the ASX platform, but we understand development by the ASX stalled and the EA has focused instead on improving the market-making of baseload futures. We strongly commend the recent and ongoing market-making efforts but we think it could be timely for the EA now to turn its attention back to financial cap products. A cap product should be explored afresh.

We think a vigorous market for caps and other risk management products would have multiple benefits. For example, they could support new entry in solar and wind generation by enabling the investors to sell their intermittent generation output to buyers that are averse to risk of high prices when the intermittent generation is unavailable.

Demand side resources that are available to respond to high spot prices could also sell cap products, which could be an important revenue stream supporting their participation in the wholesale market.

Section 4 recommendations

3. *We recommend that the EA seek to disallow persistence forecasting and require all wind generators to use acceptably accurate ways to make their offers to the SO.*

4. *We recommend that the EA explore afresh the market for cap products.*

5 Demand response and demand side participation

The key findings of this investigation concern the demand side, its potential, its use, and its neglect. While the demand side's discretionary load was put to good use in the 9 August event, it was underexploited. It could have saved the day entirely. It ought to have been fully exploited, as the available supply side was.

We propose that in future the demand side's discretionary load be accorded attention equivalent to the supply side.

Demand side activity typically does not change total load, it shifts it from peak periods to off peak periods. The starting point is ripple control (see *Ripple control and its future* box). It is a large resource, only partly used. Only a small amount is deployed as an instantaneous interruptible load.[12] It is used by EDBs to reduce transmission charges but that function will cease soon with proposed changes in the transmission pricing methodology. It will still have value to EDBs in managing constraints in their distribution network, or in delaying the cost of upgrading lines.

Otherwise, this resource is pretty much ignored. We are aware of only one company aggregating significant capacity on the demand side, probably because the instantaneous interruptible load market is so modest. A stronger market makes good sense.

5.1 Demand response could have been better on the night

At the time of the grid emergency, some EDBs had more ripple control that could have been used.[13] Further, better use of this discretionary load in the market could have altogether avoided the grid emergency that lasted over three hours.

As detailed in section 3, we estimate that there was 112 MW of hot water load available to avoid actual load cuts to over 34,000 households on 9 August. This was ripple controlled load that was:

a) not already being used to manage network peaks[14]

b) not part of an offer into the reserves market

c) not part of load directed by the SO to remain off following the grid emergency notice, and

d) not part of the response to the one per cent notice and the subsequent DAN.

[12] Some EDBs offer ripple control load into the instantaneous reserves market, but usually only outside the winter months when it is not already in use for network management. We understand there was very little ripple control offered for instantaneous reserves on 9 August given the weather conditions.

[13] Others had exhausted it in response to the one per cent GEN notice, or because they had used it earlier and then kept it off in response to the emerging events. Grid emergencies override commitments EDBs have to customers to limit hot water control to, say, four hours at a time.

[14] EDBs were using ripple control to reduce discretionary load (hot water) throughout the day on 9 August to manage their own networks, primarily to reduce transmission charges.

This load was not used because the SO was seeking load reduction according to the equity rule in the Code, rather than according to where the spare ripple control existed. This is the central reason why householders lost supply when they need not have. Section 3 describes why we think the equity rule will need to be amended to ensure that situation does not arise again.

We also found that the contribution of large consumers to solving the challenge of 9 August varied considerably. Some responded to the spot price by reducing their load or increasing their own back up generation, sometimes significantly. Others were not exposed to the spot price and were not asked to make a one per cent cut to their consumption.

Thus, some households suffered a total electricity cut while the Tiwai aluminium smelter, easily New Zealand's largest consumer, made no contribution whatsoever. This is hardly equitable. Commercial arrangements should be in place so that large industrial loads contribute to grid emergencies ahead of any household being disconnected.

We recommend that the EA demand major users are able to offer an acceptable demand side response in the event of a short term generation shortage, and regulate if commercial arrangements are not reached in a short period.

Our above recommendation, though strongly worded, is deliberately non-prescriptive.

5.2 What the system operator couldn't see on the night

The SO had no real time visibility of the ripple control potential of each EDB. They did know that the potential existed. They could, and did, find out some detail by talking with individual EDBs during the evening. But while the SO staff have good real time information on the supply side, there is no equivalent immediacy or accuracy on the demand side. This has been identified in the EA's report: *Immediate assurance review of the 9 August 2021 demand management event*. Transpower has accepted the EAs recommendation that "the SO must improve their access to information on general demand management resource availability".

Yet in our opinion it is the EDBs, not Transpower, who must facilitate change in this area. EDBs must enable this by providing the SO with the information that it needs. This obligation should be written into the Code. It may not otherwise happen in a timely and ongoing manner. It must also have an acceptable level of accuracy, at the feeder level, verified by drop testing or other acceptable means.

In short, the SO must have full visibility of discretionary load available through ripple control, enabling better and more accurate use of this valuable resource. This should be done as a matter of priority – before the winter of 2022.

The current Upper South Island load management programme is a good model to build on. It has been in existence since 2006 but has not been replicated elsewhere. It should be.

We recommend that the Code must be amended so that the SO has real time, and acceptably accurate, awareness of discretionary load available from each EDB by winter

2022. We commend the Upper South Island load management programme as a starting point.

Will EVs be part of the solution or the problem?

The increasing use of EVs will either be part of the solution or contribute to the problem. We can avoid unnecessary future increases in peak demand if EV charging is managed to shift load. The network has the capacity to deal with mass off-peak EV charging, and load shifting can help avoid events like those of 9 August.

There is uncertainty about the rate of EV uptake, the way in which consumers will choose to charge, and how they might respond to "rewards" for off-peak charging. There are also a range of technologies that could be used to manage charging (e.g. timers, in-car technology, smart phone applications), and a range of pricing incentive options.

Some EDBs already have pricing that incentivises off-peak charging, but not all retailers pass these on. Even when they do, there are misaligned incentives through the supply chain, and load shifting is undervalued.

While pricing signals that reach consumers are necessary, they are unlikely to be sufficient to avoid EVs increasing peak demand. Regulation is likely to be needed, but it needs to provide for flexibility given the uncertainty.

MBIE is one of a number of agencies looking at aspects of both public and private EV charging. It is part of a cross agency group led by the Ministry of Transport which is developing the National EV Charging Infrastructure Plan (the Plan). The purpose of the Plan is to provide long-term strategic direction as New Zealand's EV charging infrastructure system expands. The other members of the group are Waka Kotahi New Zealand Transport Agency, the Energy Efficiency and Conservation Authority (EECA).

In addition, EECA is investigating the case for having minimum energy performance standards (MEPS) for EV chargers that include demand response capability. EECA anticipates that it will be complete by early 2022.

This work is related to a broader MBIE review of the MEPS and labelling regulatory framework that could enable products to be regulated for reasons beyond energy efficiency. Regulating EV chargers for demand response capability (should there be a case to do so) would be dependent on this change, and would be unlikely to take effect until 2023.

5.3 Managing multi-hour shortfalls – the case for a new approach

In essence, the events of 9 August occurred because the system failed to reduce or shift enough load from dinner time to later in the evening. Only a small amount of electricity needed to be shifted and only for a few hours.

We call this a multi-hour shortfall. Of the possible ways to address this shortfall, we think that the idea of inventing a new product has particular merit. For all that such a product might make good market sense, we note that in 25 years of an electricity market no such a product has yet arisen and persisted.

We therefore recommend such a product begin life as a new ancillary service procured and co-ordinated by the SO alongside existing ancillary services. It might be labelled a '6 hour standby reserve' (or 4, or 12 hour) ancillary service.

Until the wholesale energy market fully embraces the demand side we think a '6 hour stand-by reserve product' will become an increasingly important tool for the SO's toolbox as intermittency increases, thermal plant retires and the residual level of flexibility to manage short term peaks reduces.

We think the introduction of this new ancillary service could be a catalyst for bringing more discretionary load to market. Should this prove attractive to market players in the years to come, more discretionary load might then become an established part of the energy market, being bid in when prices warrant it. We understand that the advent of the real time pricing (RTP) a year from now will enable this market development, and are delighted to see RTP coming to fruition.

The SO may nonetheless wish to hold some in reserve foreseeably, perhaps to offset variable wind energy when frequency keeping is threatened.

The detailed design is a matter for the EA and the SO to develop, in consultation with affected parties, particularly load aggregators, large consumers, generators and EDBs. We are aware that ancillary services will be reviewed as part of a review to ensure the electricity system remains secure and resilient in the transition to a low emissions future – as was recommended by the Electricity Price Review. The design of a 6 hour stand-by product should be considered as part of that project, but we offer some initial thoughts, informed in part by our discussions with key stakeholders.

The 6 hour standby reserve product should be designed to enable multi-hour shortfalls to be managed through a combination of demand side arrangements, and back-up generation.

Ripple control is an obvious demand side starting point. Increasing levels of battery storage may also assist, as could new demand side technologies such as electric vehicle (EV) charging (see *Will EVs be part of the solution or the problem?* box) and other discretionary load like cool stores and irrigation pumps. Demand aggregators are likely to have an increasing role to play.

The ancillary service would be defined in the Code. As with existing ancillary services, provisions relating to its role, procurement and use would be set out in the various documents that deliver system operation (such as the Policy Statement and Procurement Plan). The service would be 'called' by the SO only when agreed triggers had been reached, and the size of the product should be constrained to avoid over-insurance. Cost allocation and recovery would mirror arrangements for existing ancillary services.

We recommend the EA and SO design and implement a new product to manage multi-hour shortfalls.

We recommend that a new ancillary service be given serious consideration as the first step in the life-cycle of this new product.

The detailed design is a matter for the EA and SO to develop, in consultation with load aggregators, large consumers, generators and EDBs, amongst others.

In the interests of speed and learning, establishing a small pilot to trial such a scheme may have merit. This trial could sit alongside, and feed into other market development and design work the EA and SO are undertaking as we look to the future.

Ripple control and its future

Ripple control dominates the demand side of the New Zealand electricity system. It is about 70 years old, cheap to run and widespread. It is a signal sent down power lines that turns things off and on – usually domestic hot water cylinders. Most householders don't notice when or if it happens and many don't know even if ripple control is present in their home.

But any system that can turn off well over a million hot water cylinders deserves closer examination.

EECA published such an examination last year (available at: www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/Ripple-Control-of-Hot-Water-in-New-Zealand.pdf)

It is a comprehensive, sensible and accessible report. We strongly commend it.

The ripple control system functions, not by saving energy consumption, but by shifting it – from peak periods of the day to off peak periods. Therefore, its main function is to reduce transmission or distribution lines overloading, or to delay the cost of lines upgrades, thereby improving efficiency and keeping costs lower.

But on 9 August the ripple control system was deployed for another reason altogether – to reduce the load over a several hour period. A shortage of generation meant that the system frequency was dropping below the requisite 50Hz. Unchecked, this would have led to an Automatic Under Frequency Load Shedding (AUFLS) event in which 16 per cent of the system would have been shut off, automatically.

So, ripple control has two distinct roles. One is to avoid a constraint in transmission or lines networks. Another is to compensate for a generation shortfall.

These two roles compete. They competed on 9 August because hot water cylinders that had already been turned off on a cold evening to stop network constraint were not available to be turned off again to address an emerging under-frequency event.

That might be an obvious remark. But it helps explain why the reforms of the past quarter century have not resulted in the ripple control system carving out a clear role or clear future. In all, it is the most powerful component of the system's demand side but it has no singular mandate. It is used in part to fill Transpower's instantaneous demand market, but not in large part; some retailers offer tariffs that reflect access to ripple control, others don't; some EDBs use it assertively to hold costs; others have abandoned its use; some smart meters allow ripple control to connect to EVs (say); others don't.

Ripple control is cheap. It costs in the order of 10 to 20 per cent of an alternative on the supply side such as an embedded gas peaking generator. But the value does not fully accrue to the EDBs who maintain it. This mismatch will become exacerbated next year when proposed changes to transmission pricing reduce the value of ripple control to EDBs. There is a slow (approximately one per cent per annum) decay in the number of ripple control connections underway now, which may quicken.

That should not be allowed to happen. Ripple control technology more or less saved the day on 9 August – and could have done so even more comprehensively had it been properly deployed. Though a simple and old technology, ripple control forms the foundation for a much more comprehensive future when hot water cylinders and other forms of energy storage can be controlled more precisely and in smarter ways. Artificial intelligence (AI) and the Internet of Things (IoT), inter alia, will likely strengthen the demand side materially and soon. As we move towards a fully renewable (and more intermittent) future for generation, we will increasingly need techniques to shift energy consumption to different times of the day.

The demand side is good at that and is able to become better, so long as good rule making helps and does not hinder its development.

Section 5 recommendations

5. *We recommend that the EA demand major users are able to offer an acceptable demand side response in the event of a short term generation shortage, and regulate if commercial arrangements are not reached in a short period.*

6. *We recommend that the Code must be amended so that the SO has real time, and acceptably accurate, awareness of discretionary load available from each EDB by winter 2022. We commend the Upper South Island load management programme as a starting point.*

7. *We recommend that the EA and the SO design and implement a new product to manage multi-hour shortfalls.*

8. *We recommend that a new ancillary service be given serious consideration as the first step in the life-cycle of this new product.*

6 Information and communications

Communication during and following the events of 9 August has attracted widespread criticism from industry participants, consumers, government and media.

A widely held view is that the nature and standard of communication in the sector is neither modern nor responsive. In particular, Transpower as the SO has room for improvement. Three reviewers have already offered comment on Transpower's communications on 9 August. Our own remarks seek to avoid undue repetition.

Elsewhere in the sector, ownership of the customer relationship is contested under conditions of stress. In short, retailers have the primary relationship but in emergencies EDBs have the most accurate and current information.

Medically dependent customers are a sensitive issue among industry participants, especially retailers, who often instanced them as a key reason why communication and information flows should improve.

We have tried to distil a useful way forward, and propose some pragmatic suggestions.

6.1 Transpower has operational communications systems

The SO has a well-documented system of notices for distributing operational information to registered market participants and to interested parties who subscribe. These notices are described elsewhere in this report.

Transpower operates the National Coordination Centre (NCC) which is the SO's two national dispatch and market scheduling control centres. It is operations staff in the NCC who are responsible for determining the appropriate operational actions needed to ensure grid security and communicating those actions to the relevant parties.

Transpower also operates the National Grid Operations Centre (NGOC) which is the grid owner's three national grid switching control centres. NOGC staff were also involved in communications with EDBs.

6.2 Transpower's communications fell short on the night

Transpower's communication record on the night was clearly unacceptable for multiple reasons. People were given wrong information, late information or no information. The information was delivered predominantly by email, even well into the evening. The NCC and NGOC also deployed considerable telephony to seek or confirm load-shedding and to try to correct, or to reinforce, wrong information they had inadvertently issued.

Of particular note is that Transpower did not advise the office of the Minister of Energy and Resources until 19:51 and then only by email to the Private Secretary. The Minister did not find out until 20:30 when the media rang her Press Secretary. Transpower's Chair and Directors were emailed at 22:21. Shareholding Ministers found out via the media.

Unsurprisingly this has led to multiple reviews and actions. We have considered the EA's Immediate Assurance Review report, and reports by PBA and Thomson Lewis (both commissioned by Transpower) which included consideration of the SO's communications around the event. Executive summaries of each are annexed to this report.

We concur with the findings and recommendations relating to Transpower communications in all three of these reports, which we consider address most of the issues discussed above. Recommendations relate variously to enhanced communications arrangements with control rooms, market participants, the public and key government stakeholders, and also to enhanced communication channels, including addressing an over-reliance on emails.

We commend Transpower for accepting the EA's report in its entirety and for making immediate changes to its communication processes during national grid emergencies, particularly with EDBs and direct connect customers. We note that Transpower has also provided a response to the EA setting out its plans for addressing the EA's findings.

We acknowledge that improved communication was reportedly very evident in a grid emergency event at Weka Pass the following week.

We also note Transpower's acceptance of the findings of the two reviews it commissioned, and its public commitment to implementing the necessary changes.[15]

Nonetheless, similar Transpower communication failings have at times been identified before, apparently ineffectually. In Transpower's report into 2 March 2017 South Island AUFLS Event, it was found that:

> *"Key Lesson 3: Our operational communications (and those of our counterparts at the generators and distribution companies) are not meeting required protocols in high pressure situations."*[16]

It would be untenable for this to happen again.

We recommend that the EA and Transpower address the findings and recommendations in the EA's Immediate Assurance Review report, and reports by PBA and Thomson Lewis (both commissioned by Transpower) as a matter of priority, with each immediately initiating a programme of work, co-ordinating where appropriate.

The above observation regarding previous communication failings, coupled with the strength of findings from the EA and Transpower reviews of 9 August, have further informed our recommendation that Transpower and the EA each provide a quarterly report to the Minister of Energy and Resources setting out progress until the systems are in place, and that the EA provide subsequent compliance monitoring.

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[15] Available at: www.ea.govt.nz/assets/dms-assets/28/Letter-Transpower-Response-to-EA-Phase-One-Review-24-September-2021.pdf and www.ea.govt.nz/assets/dms-assets/28/Letter-Attachment-Transpower-Response-to-EA-Phase-One-Review-24-September-2021.pdf

[16] 2 March 2017 South Island AUFLS Event Summary of Incident Investigation Reports and Findings, April 2018, www.transpower.co.nz/sites/default/files/publications/resources/Report%2520on%25202%2520March%25202017%2520South%2520Island%2520AUFLS%2520Event.pdf

We offer a couple of suggestions augmenting those already made by others. One is that Transpower ensure that it has competent communication resources at work, preferably on site, whenever the SO is dealing with an emergency (perhaps using agreed triggers). That would ensure Transpower's new and improved communications policies can be effected without disturbing the SO's more important job of keeping the lights on.

Second, we observe that managing emergencies such as these requires co-ordinated timely and well-informed actions by the SO and a large number of participants up and down the country. Many of the issues that faced the SO on the night would have emerged and been resolved had there been a recent pan-industry contingency exercise to test processes, actions and communications and to clarify responsibilities. The EA should ensure such exercises are conducted.

Indeed, we think Transpower might consider answering those critics who say the organisation is insular by inviting the National Emergency Management Agency to help devise quality communication tactics and systems for use in emergencies. We therefore make the following recommendations which are arguably not fully captured by other reviewers:

- Transpower should ensure that it henceforth reliably and promptly provide the 24/7 communications needs of the SO in generation emergencies.
- Transpower should design and undertake pan-industry contingency exercises, monitored by the EA, sufficient to test processes actions and communications, and to clarify responsibilities in a generation emergency. Transpower should consider engaging the National Emergency Management Agency to help in designing communications policies for use in an emergency.

6.3 Consumer information and communication with the public was poor

Communication was a very common theme raised during this review and it had many different shades. The public was generally unaware of the unfolding grid emergency until their electricity was cut, and there was considerable public confusion during the event. Social media pages were awash with questions and complaints on the night and in the days that followed.

Medically dependent consumers were of particular concern to retailers and their specific information needs are considered later in this section.

A lack of authoritative relevant up-to-date information, crafted in language suitable for the public, and made available in a timely and readily accessible manner was, we believe, at the heart of the problem. This begs the questions: what information, and who should provide it? We have tried to provide answers to those questions which meet the key needs of the public, but which are also practicable in emergency settings.

The SO had the most up-to-date information. However, the SO had no idea of how each EDB would deliver the SO's required load reductions. Only the EDB knew which suburbs were being cut off, if any.

It follows that both the SO and the EDB have obligations to communicate to the public. Just how communication is effected is a matter for the parties to decide as they develop more streamlined practices. However, we do not accept that posting on a website is sufficient, as some industry players have opined.

In our view the most important information a consumer can receive during a power cut is an estimate of the likely duration. Such an estimate was not forthcoming, though a rough guess at the duration was surely plausible.

We endorse the recommendation of PBA Consulting that the SO should improve its process for providing the public with timely and simple explanations for system-wide incidents, particularly where consumers have been disconnected.

However, we add that EDBs will usually hold relevant information that the SO does not, and are therefore also obliged to establish communication protocols, by multiple means. Both the SO and EDBs should be proactively in touch with all retailers, and should have established and agreed systems to achieve that.

We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication, and encode such arrangements where appropriate.

We make two further points:

- Disconnection in emergencies is not a planned outage: We disagree with the notion that the disconnection of consumers on the evening of 9 August was either planned or reasonably foreseeable. Instead, a series of unrelated events collectively created an emergency.
- Public warning system is inadvisable: Earlier in our investigations we had formed a tentative view that the public should receive a warning of potential supply interruptions in such emergencies, and that the SO should develop a nationwide public alert system. We changed our minds. As 9 August demonstrates, it is very difficult to predict with much certainty that disconnection will be needed. Actual disconnection is rare, and most warnings will therefore turn out to be false alarms. Public warnings could result in a surge in demand sufficient to tip a possible emergency into a full blooded one. Or if worded to minimise that result, then it might well induce the opposite risk of (especially older) consumers heavily cutting consumption at the expense of their wellbeing.

6.4 Communication with medically dependent consumers can improve

Medically dependent consumers are a sensitive issue among industry participants, especially retailers, who often instanced them as a key reason why communication and information flows should improve.

We engaged in many conversations about how best to prioritise communication to these consumers, before concluding that doing so risked doing more harm than good. Prioritising communication would be reliable only if systems allowed the electricity system to have very accurate detail on how to contact the current list of medically dependent consumers. This is impractical given the ever-changing needs of patients, during a pandemic or not, and differing attitudes to patient confidentiality.

All households suffer unplanned electricity outages, typically about two per year. Therefore, the most important thing a medically dependent consumer can have is an emergency response plan. This is developed with their clinician and tailored to their particular circumstances. It is this plan, rather than a communication from an electricity retailer, which the medically dependent consumer should rely upon.

As with all consumers, the most important piece of information at the time of a power cut is some idea of the likely duration. This information was not readily available on the night, when it reasonably could have been. It should be available, according to an agreed communications plan, and via multiple media and communications outlets.

We commend those retailers who proactively called their medically dependent consumers, typically the following day, to check on the status of their emergency response plans. We note that some retailers were unable to identify which consumers were affected.

We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication with medically dependent consumers, and encode such arrangements where appropriate.

Noting that these arrangements may not be materially different from those applying in the above recommendation, we suggest that the EA and industry also consider an education campaign to ensure medically dependent consumers are aware of the importance of having a personalised emergency response plan.

Section 6 recommendations

9. *We recommend that the EA and Transpower address the findings and recommendations in the EA's Immediate Assurance Review report, and reports by PBA and Thomson Lewis (both commissioned by Transpower) as a matter of priority, with each immediately initiating a programme of work, co-ordinating where appropriate.*

10. *We recommend that the EA and Transpower should each be asked to provide quarterly updates to the Minister of Energy and Resources setting out progress until the systems are in place. The EA should undertake subsequent compliance monitoring.*

11. *Transpower should ensure that it henceforth reliably and promptly provide the 24/7 communications needs of the SO in generation emergencies.*

12. *Transpower should design and undertake pan-industry contingency exercises, monitored by the EA, sufficient to test processes actions and communications, and to clarify responsibilities in a generation emergency. Transpower should consider engaging the National Emergency Management Agency in designing communications policies for use in an emergency.*

13. *We endorse the recommendation of PBA Consulting that the SO should improve its process for providing the public with timely and simple explanations for system-wide incidents, particularly where consumers have been disconnected.*

14. *However, we add that EDBs will usually hold relevant information that the SO does not, and are therefore also obliged to establish communication protocols, by multiple means. Both the SO and EDBs should be proactively in touch with all retailers, and should have established and agreed systems to achieve that.*

15. *We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication in a grid emergency, and encode such arrangements where appropriate.*

16. *We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication with medically dependent consumers in a grid emergency, and encode such arrangements where appropriate.*

17. *Noting that these arrangements may not be materially different from those applying in the above recommendation, we suggest the EA and industry also consider an education campaign to ensure medically dependent consumers are aware of the importance of having a personalised emergency response plan.*

7 Looking ahead

Looking ahead, are the current arrangements capable of delivering appropriate levels of security and reliability?

The short answer is that we lack the analytical capacity to definitively answer the question. But we do have some observations to make, rising from our investigations and the insights that have emerged.

The question is important because it typically involves balancing two 'goods' – affordability and security of supply. How much of one might we wish to trade off against the other? Our observations in this review do not particularly address a commonly understood meaning of security of supply – that of a dry winter. Instead we focus on a less often considered source of insecurity; that caused by a peak generation shortage, perhaps increasingly exacerbated by intermittent generation from renewables.

The distinction matters. Unlike many other countries, electricity system challenges in New Zealand usually arise from a shortage of fuel – water – and rarely involve a shortage of peak generation capacity. Elsewhere in the developed world the opposite is usually the case – there is typically plenty of fuel (usually fossil fuel), but a shortage of generation capacity.

On 9 August New Zealand's 25 year old electricity market suffered its first generation capacity shortage that was severe enough to cause the lights to go out in 34,000 homes. There was no shortage of fuel on 9 August, and no shortage of transmission capacity.

Put another way, had either of the two slow-starting thermal plants been operating, the night would have passed without notice. Yet we are imagining a near future where those aging slow thermal plants will be removed totally from the market, and are asking ourselves whether current security arrangements will get us through on some other cold winter's evening.

Our indecision in answering that question arises partly because there are a number of significant unknowns on the supply side – the future of aluminium smelting, green hydrogen production and Lake Onslow generation. The progressive removal of slow-starting thermal generation capacity is therefore only one piece of a bigger puzzle. Additionally, there are the usual and persistent questions around the timing and extent of investment in new generation.

Change in the demand side is a little more certain, though the rate of change is unclear. The uptake of EVs or the speed of the conversion of process heating to electricity, and the move of households away from gas are subject to some speculation and are also price dependent.

Nonetheless, some things are rather certain. It is clear that ongoing attention must be paid to deepening the market for various products, especially various hedge products. We have made the case for adding a cap product to the mix. We believe that these moves will encourage new or existing generators to invest further, and that failure to continue to deepen the market will chill such investment.

We think it is certain that the SO and/or the market will need one or more products in the near future that can shift load from one part of the day to another. We call these 'multi-hour products'.

We note that in the first 25 years of the electricity market such a product has not arisen and persisted by itself. We envisage such a product may begin as one of Transpower's ancillary service products but become a market product in time. We further envisage that such products will be dominated by the demand side initially, given the low cost of ripple control, and will grow from there.

Society has an increasing intolerance of electricity cuts. As the demand side mechanisms develop there will be less and less buffer for the SO to draw on in times of generation shortage. That means ripple control will not be available to save the day as it did, or could have, on 9 August. Additionally, climate change will increasingly test system resilience.

That begs the question as to whether the SO should adopt a more conservative posture. A simple way to frame the question would be 'should we have a redundancy setting of, say, n – 2 not n – 1?' Such a move might encourage additional investment, but may also raise prices marginally.

A more thorough analysis than we can provide is called for.

The only thing we are sure of is that, right now, innovation matters.

Why is innovation crucial?

Innovation is nothing new in the New Zealand electricity sector. From the moment gold miners needed to shift energy from one valley to the next, through wires over an Otago mountain ridge, the industry has embraced innovation, often boldly.

New Zealand electrified relatively early. We built hydro stations in remote gorges or inside a mountain; we deployed a national grid system across both major islands, we used ripple control to shift load, we extracted heat from the earth's crust. And we are still doing all that.

Then we became leaders in the development of an electricity market, some aspects of which have become widespread or standard globally.

Now we are adding wind and solar and biomass, we are contemplating a hydrogen future, and researchers muse about how to transmit electricity a kilometre through air or about how to create it from roofing tiles, and other weird things.

It becomes still more complicated and interesting when the demand side is added. We can shift electricity load from one part of the day to another, from peak to trough, by using not just our hot water cylinder, but our dishwasher, or increasingly our electric vehicle. And that can be a commercial prospect; consumers can save a bit of money, or even make some if one adds roof top solar generation.

New technology, solar power in particular, means that we are entering a period of technological development where the marginal, or perhaps the levelised, price of electricity is reducing. This is the obverse of recent history which has hitherto seen an inexorable rise in cost of the 'next' source of generation. The speed of adjustment is still a little uncertain, even if its inevitability is beyond doubt, and it has very significant implications.

But this complicated and interesting future needs some leadership from the centre, in two main areas.

The first is in setting minimum functional standards so that, for example, good two-way communication can occur between the meter or the cell phone and the electric vehicle or the dishwasher. Electricity meters and appliances alike must meet standards so that they respond intelligently. It is the role of MBIE and the EA to develop those standards through Standards New Zealand. If standards are not set, in a comprehensive and timely manner, industry will fill the void and they will logically act in their interests and not necessarily in the public interest. We recommend that both MBIE and the EA demonstrate leadership in this area.

We wish to acknowledge the considerable existing work programme in this regard; the analysis by officials in MBIE and the EA as they think ahead, the engagement of industry, and the political determination to make regulation a facilitator of innovation, not its handbrake. These apparently prosaic actions are very important, and they are not always easy to get right first time.

The second is in developing, or purchasing, the IT capability to allow the embarrassment of riches of a well-integrated electricity system to be harnessed. Of course, much of this integration exists at the moment. But much doesn't. We have different parts of the system developing at very different speeds and according to individual company strategies.

Various sector leaders are to be congratulated and encouraged. It is noteworthy that significant innovation is happening among both established and larger players as well as the new, small challengers.

But the centre must place a more coherent, experimental and inaugurating role. It must increasingly embrace the next stages of IT – the various components of artificial intelligence, neural or virtualised networks, and the like. We particularly see a role for Transpower. Some may see Transpower as a statutory monopoly with a staid and aloof posture. But it is also where many of New Zealand's finest power system engineers and other thinkers go to work. They are well placed to make the centre a better brain than it is now.

We should raise our expectations of them to do so. Transpower must demonstrate it operates at the frontiers globally, and it must have license to make mistakes. Our system must be smarter, more integrated and more able to embrace the next technical change.

Furthermore, the next wave of social change is upon us. The direction of social change is clear, and the pace has started to quicken. Consumers will increasingly want to buy clean energy, at an acceptable price with increasing reliability. They will increasingly generate their own electricity, variously, and will increasingly store or sell any excess. The distinction between supply and demand will become increasingly blurred.

While some of us will continue to view electricity as an undifferentiated commodity, others are engaging with emerging electricity products to an unprecedented extent. It is this second group that will catalyse change.

The last word on innovation concerns efficiency. From the beginning, the electricity sector has traded security and price – how much of each do we want of each 'because you can't have both.' Innovation challenges that. It says you can have both. What is more, you can decarbonise as you go. Some efficiency gain comes from the application of artificial intelligence and the like, some comes from new energy technologies like solar or battery, and some comes from new business models, such as attention to the demand side which has been the focus of this review.

We will still need to build some big renewable generation kit, but innovation allows us to sweat what we have a lot harder.

Section 7 recommendations

18. *MBIE and the EA should demonstrate leadership in their respective roles in standard setting where it is in the public interest to harness emerging demand side opportunities.*

Annexes

Annex A: Terms of Reference

Document also available at: www.mbie.govt.nz/dmsdocument/16637-terms-of-reference-investigation-into-electricity-supply-interruptions-of-9-august-2021

Investigation into electricity supply interruptions of 9 August 2021

Purpose

- To understand the causes of power supply interruptions on the evening of 9 August 2021, when more than 34,000 consumers lost power in the evening following a direction from the System Operator to curtail national demand, and
- To learn lessons from the event to identify and recommend improvements to ensure similar circumstances are better managed in future.

Background

In the evening of Monday 9 August 2021, Transpower, the electricity industry's System Operator, issued instructions to electricity distributors and its directly-connected customers to reduce demand by 1 per cent, in order to balance supply with demand during the evening peak demand period. This resulted among other things, in a power cut for more than 34,000 consumers.

The Minister of Energy and Resources has directed the Ministry of Business, Innovation and Employment (MBIE) to investigate and report on this event.

Scope

The investigation will investigate and report on the causes and factors contributing to the power supply interruptions of 9 August, and make recommendations that will enable relevant parties (including Transpower, the Electricity Authority, and electricity industry participants) to reduce the risk of supply interruptions and to appropriately manage any demand curtailment that might result from insufficient generation or other constraints.

The investigation will address the following questions, and any other matters consistent with the purpose of the investigation.

Communications when interruptions are imminent or expected

1. When there is a material risk that power will be curtailed, as a last resort emergency measure, how can consumers be better informed of the timing and duration of any power interruption?

2. What improvements to industry communication processes are needed to ensure medically dependent and vulnerable consumers are given adequate notice of power interruptions?

3. What improvements are needed for the system of notices that signal a potential shortage situation to generators, network businesses and directly-connected customers?

4. What improvements can be made to ensure timely and effective communications for other stakeholders, including the Minister, regulators and relevant officials, emergency services and health or welfare services?

Forecasting, scheduling and risk margins

5. Was all operable generation plant operating at its maximum available capacity during the evening peak on 9 August and if not why not?

6. What improvements could be made to the methods and processes used to forecast electricity demand and to schedule sufficient generation to meet the forecast demand with sufficient margin to cover contingencies (such as inadequate wind, generation outages and transmission outages)?

7. Given the critical and growing importance of reliable electricity in modern life, what level of risk of supply interruption should be tolerated? What security margins should apply when the System Operator is scheduling power system reserves?

8. Looking ahead, are the current arrangements capable of delivering appropriate levels of security and reliability?

Ensuring adequate standby generation or other resources to reduce risk

9. Given the lead times necessary for some generation resources (and demand management resources) to be ready to generate when required (many hours in some cases), what mechanisms are warranted to enable or ensure those resources are offered or made available to be brought into service when needed?

10. What mechanisms are necessary to ensure that emergency load curtailment results in minimum disruption to consumers, for example controlling hot water load or other low value demand before other load is interrupted?

Roles and accountabilities

11. Is there adequate clarity of roles, responsibilities and assurance mechanisms for the policies, procedures and tools that collectively deliver electricity system operation and emergency management?

12. Are there appropriate arrangements for monitoring, and periodically reviewing, the adequacy and effectiveness of electricity system emergency management plans and policies?

Interdependencies

The investigation may draw upon any relevant information and insights from other reviews or investigations underway or completed, including:

- Transpower's internal reviews of its performance and its supporting tools, processes and communication practices as System Operator, and
- The Electricity Authority's review, under section 16 of the Electricity Industry Act, of how the electricity system performed on 9 August 2021.

Transpower and the Electricity Authority have agreed to provide information and support for the purposes of this investigation.

Out of scope

For clarity the following matters are out of scope:

- Determining any breach of the Code or other laws
- Addressing methods to reduce electricity demand or to encourage generation investment
- Considering ownership or institutional governance arrangements in the sector

Approach

The investigation is expected to:

- Seek and consider information on relevant circumstances, events and actions leading up to, during and immediately following the 9 August event
- Take into account the perspectives of relevant parties
- Consider relevant reports and information, such as from Transpower and the Electricity Authority, including previous relevant reviews and reports.

Timeframe and deliverables

The investigation is to commence on 19 August 2021 with a target date for conclusion of 6-10 weeks later.

A written report will be prepared incorporating all of the details required to satisfy the purpose of the review.

A draft report or summary of the findings will be shared with key parties including the Electricity Authority, Transpower and any other directly affected parties, to enable an opportunity to comment and provide input before the report is finalised.

Roles and responsibilities

The sponsor of the investigation will be Chris Bunny, Deputy Secretary, Building, Resources and Markets, MBIE.

The investigation will be led by Pete Hodgson, with Erik Westergaard being the specialist technical advisor.

The investigators will keep the sponsor informed of progress and engage on the draft findings and recommendations.

MBIE will provide secretariat support.

Annex B: Glossary and description of terms

<table>
<tr><th>Term</th><th>Description</th></tr>
<tr><td>Ancillary Services</td><td>The system operator contracts market participants to support the reliable operation of the New Zealand power system with the following ancillary services:
Frequency Keeping
Over-frequency reserve
Instantaneous reserve
Black Start
Voltage support
Current providers:www.transpower.co.nz/system-operator/electricity-market/current-contracted-providers
More information at: www.transpower.co.nz/system-operator/electricity-market</td></tr>
<tr><td>AUFLS - Automatic Under Frequency Load Shedding</td><td>A set of relays which automatically trip blocks of load, following a severe under-frequency event, to restore the system frequency.
Current Code arrangements:
The following must “arm” two blocks of load (of at least 16% of the provider’s total network demand) for AUFLS provision:
North Island – parties ‘directly connected to the grid’:
EDBs – satisfy by arming some of their feeders with AUFLS relays, and
directly connected consumers (some of whom have temporary exemptions) are expected to satisfy the obligations by arming certain components of their site load with AUFLS relays
South Island – Transpower as grid owner – “arms” AUFLS relays on feeders at grid exit points, including at NZAS which has one pot line armed.
More information is at www.transpower.co.nz/system-operator/electricity-market/automatic-under-frequency-load-shedding-aufls</td></tr>
<tr><td>Consumer Advice Notices (CANs)</td><td>Notices regarding events happening on the power system – there can be several one day and none another. Low Residual Situation CANs are sent out when the system operator calculates that residual generation is less than 200 MW in one island or nationally for an upcoming trading period.
Participants are asked to ensure energy and reserve offers and load bids are accurate for the relevant period, and to advise the system operator by phone of any information that could impact system security.
These CANs state that, if system conditions worsen, it could result in a Formal notice (WRN or GEN) being issued due to insufficient offers being available to</td></tr>
</table>

	cover for the largest contingency or meet demand and maintain frequency keeping reserve.
Demand Allocation Notice (DAN)	The notice that sets out load shedding instructions to network companies from the system operator. Instructions are based on calculations from a Load Shed Restore (LSR) tool used to reallocate the initial reduced demand (from prior GEN) so that the final demand reduction is equitably shared amongst EDBs.
Demand side participation in wholesale market	The most general form of demand side participation is when consumers that purchase electricity at spot prices (including through a retail contract) choose to reduce or increase demand in anticipation of the price in a particular period. The demand side can also participate in the instantaneous reserve market by offering interruptible load, often through an intermediary. Additionally, some consumers (typically large industrials) with good control of their electricity consumption can be dispatched on the basis of price-quantity energy bids. More information is at: www.ea.govt.nz/operations/wholesale/spot-pricing/dispatchable-demand
Discretionary load	Electricity load that is not necessary to a consumer at a particular point in time. The most obvious example is electricity used to heat water stored in an insulated cylinder. Such electricity consumption, called controlled hot water demand, can generally be interrupted for short periods of time (hours) without affecting the quality of the hot water service. Controllable hot water demand is actively managed by many if not most EDBs, currently through the use of ripple control technology. Business consumers may also have some discretionary load, such as irrigation pumps and refrigeration, which can be interrupted for short periods without adversely affecting overall service levels.
Electricity Distribution Business (EDB)	There are 27 local electricity distribution businesses (lines companies) in New Zealand that take power from the national grid and deliver it to homes and businesses. More information is at: www.ena.org.nz
Electricity Industry Participation Code 2010 (the Code)	The Code sets out the responsibilities of electricity industry participants, including the Electricity Authority's duties and responsibilities. It is available here: www.ea.govt.nz/assets/TheCodeParts/FULL-MERGED-CODE-1-September-2021.pdf
Formal notices (from the SO)	Formal notices inform participants of events happening on the power system that require parties to take some action. These include Warning Notices (WRN) and Grid Emergency Notices (GEN).

	WRNs and GENs advising of insufficient generation offers are relevant to this investigation. WRNs typically request that participants increase offers for generation and/or instantaneous reserves and may ask them to reduce demand. If there is insufficient response to a WRN, it will escalate to a GEN where participants are again requested to increase offers for generation and/or instantaneous reserves and to reduce demand. In more extreme situations a GEN will include a mandatory demand reduction instruction. See *Demand Allocation Notice* and *One per cent notice*
Frequency Keeping	The grid needs to operate within a particular band of frequency. The SO uses frequency keeping services to manage short term supply and demand imbalances to ensure that the system frequency is maintained at or near 50 Hz. In the event of a sudden loss of grid injection, system frequency will fall. If the supply-demand imbalance is not corrected, frequency will continue to fall. If it drops below the minimum levels generators can tolerate, they will start to trip and cascade failure leading to black-out may occur. To prevent a black-out following the loss of grid injection, the system is brought back into balance through the rapid increase of generation or the dropping of some load. Depending on the nature of the risk, the system operator has different arrangements for procuring under-frequency management resources. Frequency keeping can be provided by one or more generators (certain battery operations can also provide it but none currently do). Generators dispatched for frequency keeping cannot also provide *instantaneous reserves* or energy.
Grid emergency	In general, the system controller will declare a grid emergency when it appears the system is in, or is entering, an insecure state, and operation of the wholesale market is not sufficient, or sufficiently timely, to securely balance supply and demand. It is not uncommon for a grid emergency to occur in one region of the grid due to a transmission fault, or due to a generator fault in a region that depends on local generation. In such situations the SO may require the affected distributors to reduce demand in the region. System-wide grid emergencies that require a nation-wide call for load-shedding, as occurred on 9 August, are very uncommon.
Instantaneous Reserves (IR)	As the name suggests, instantaneous reserves operate automatically when needed in the event of a sudden failure of a large generating plant or the high-voltage direct current (HVDC) link between the North and South islands.

	There are two forms of instantaneous reserve – Spinning Reserve (provided by generators) and *Interruptible Load (provided by electricity consumers).*
Interruptible Load (IL)	One of two ways the SO contracts to maintain grid stability when large disturbances occur on the system – covers the risk of the loss of the single largest supply asset (known as the contingent event). It is provided by participants that control consumers' demand (typically at an industrial site) and can provide the service of reducing energy consumption. Part of *Instantaneous Reserves*
MW	Megawatt – standard term of measurement for electricity.
One per cent notice	The *Formal notice* issued by the SO at 18:47 on 9 August instructing network companies to reduce demand by one per cent of the 7,120 MW total demand at the time.
Real time pricing (RTP)	The Code was recently amended to overhaul the way spot prices are determined – called 'real time pricing' (RTP) – which is due to be implemented in late 2022. RTP is expected, among other things, to enable much more *demand side participation* in the *wholesale market* using a new arrangement called dispatch-lite, which is expected to make it easier for small consumers and generators to be dispatched. More information is at: www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/background/
Residual Generation	A term for offered generation that is not 'cleared' in a pre-dispatch schedule, and is therefore available to be dispatched by the SO if necessary to meet demand – for example, in response to an unexpected reduction in dispatched generation or an increase in demand. If there is not enough residual generation, the SO may curtail demand to ensure system security.
Spinning Reserve	Instantaneous reserve provided by a generator is called spinning reserve, and may be provided by a partly loaded unit or by a hydro unit that is spinning in air. Part of *Instantaneous Reserves*
Spot market	The spot market, for the purposes of this investigation, means the arrangements through which generation and other resources are scheduled and dispatched, every half hour, to meet the demand for energy and ancillary services necessary for a secure power system. The ancillary services most relevant to this investigation are *Frequency keeping* and *Instantaneous reserve*.

System Operator (SO)	Transpower is contracted to act as system operator and to coordinate supply and demand resources in real-time to make sure the lights stay on at the lowest possible cost. This is provided for in the Electricity Industry Act (2010), and Part 7 and Part 8 of the *Code* in particular. Ensuring real-time security requires the system operator to manage the power system so that there is a continuous balance between electricity supply and demand. It also requires all parties connected to the transmission grid continuously meeting their asset owner performance obligations and technical requirements prescribed in Part 8 of the *Code*. The system operator is also responsible for investigating and planning activity over periods ranging from minutes to years ahead of real-time. This work includes assessing security of supply, helping to coordinate generation and transmission outages and ensuring new generators meet *Code* requirements for system reliability. The system operator also enters contracts with generators, retailers and distributors for essential *ancillary services*, in accordance with policies and procurement plans that form part of the *Code*.
Wholesale market	The electricity wholesale market generally includes any trading of electricity and related products and services that do not involve a consumer. Trading with consumers happens in the retail market. The boundary between the wholesale and retail markets can be blurred because some consumers purchase electricity at wholesale spot prices and may trade in wholesale risk management products that are derivatives of the spot price. Wholesale risk management products include electricity futures and financial transmission rights. The wholesale spot market has a very near term focus, while other parts of the broader wholesale market are longer term in nature. Futures, for example, cover periods up to four years ahead, and some bilateral agreements – such as power purchase agreements – may cover periods a decade or more ahead. Forward prices provide important information for investment decisions by generators and other participants. See *Spot prices*

Annex C: Stakeholders, data and evidence

As part of the investigation, we spoke to a range of stakeholders as set out in the table below.

Retailers	Generator Retailers	Industry bodies and groups
Electric Kiwi Flick Electric Haast Energy	Contact Energy Genesis Energy Mercury Energy Meridian NZ Nova Energy Pioneer Energy Trustpower	Electricity Authority (EA) Electricity Networks Association (ENA) Electricity Retailers' Association New Zealand (ERANZ) Energy Efficiency and Conservation Authority (EECA) Transpower (including as system operator)
Major users	**Electricity Distribution Businesses**	**Other**
New Zealand Aluminium Smelter (NZAS) New Zealand Steel	MainPower New Zealand Orion New Zealand Unison Networks Vector WEL Networks	Brent Layton (previous Chair, EA) Carl Hansen (previous CEO, EA) Enel X Heather Roy (Chair, Security and Reliability Council) Lodestone Energy

In addition to information gathered in the stakeholder meetings, we drew on a range of other information sources. The key sources were:

Data and evidence

- Transcripts of relevant system coordinator and grid asset controller conversations held on the evening of 9 August (intra-office and with distribution companies and generators)
- Notices issued by the system operator on 9 August
- Provisional and interim prices by trading period and GXP on 9 August, and 8-10 August dispatch 'instructions'
- Generation offers and cleared generation data (energy and reserves) for 2-11 August

- Generation outage data provided to MBIE by Contact, Genesis, Mercury, Meridian and Trustpower
- Planned outage information from the Planned Outage Co-ordination Process (POCP) database
- Information provided by electricity distribution businesses to the Electricity Authority outlining load control responses on 9 August
- Information from Transpower on load and weather forecasting

Resource documents

- *Ripple Control of Hot Water in New Zealand* www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/Ripple-Control-of-Hot-Water-in-New-Zealand.pdf
- *Electricity in New Zealand* www.ea.govt.nz/assets/dms-assets/20/20410Electricity-in-NZ-2018.pdf
- *Energy in New Zealand* *www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/energy-in-new-zealand/* and dashboard
- www.transpower.co.nz/system-operator

Reviews by other parties (refer annexes D, E and F for summaries and links to full reports)

- Electricity Authority - *Immediate assurance review of the 9 August 2021 demand management event*
- PBA Consulting – *Independent Investigation of the 9 August 2021 Grid Emergency for Transpower New Zealand*
- Thompson Lewis – *Review into Transport Communications 9 August 2021 Grid Emergency*

Annex D: PBA Consulting Report Independent Investigation of the 9 August 2021 Grid Emergency – Executive Summary

Full report available at: https://transpower.co.nz/sites/default/files/news-articles/attachments/PBA%20Consulting_9%20Aug%2021%20Grid%20Emergency%20Investigation_Final%20Report.pdf

Executive Summary

I. Brief Description of the Grid Emergency

In the two days leading up to the Grid Emergency, the System Operator began forecasting a possible record high NZ peak demand for the evening of Monday 9 August 2021. Initially, there was sufficient generating capacity offered to meet the forecast demand as well as provide a normal reserve margin to cover for the possible loss of generation.

As the Monday evening peak demand approached, an unexpected loss of hydro and wind generation resulted in the total available generation only just meeting the demand. In order to keep control of system frequency, the System Operator followed policy and issued a Grid Emergency Notice (GEN), instructing distributors to reduce demand by 1% of the 7120 MW total demand at the time.

Distributors responded immediately by turning off controllable load, or by disconnecting consumers where no more controllable load was available. The 1% demand reduction (71 MW) was achieved in 6 minutes, and reached 3% (243 MW) 20 minutes after the GEN. This reduction allowed the System Operator to keep control of system frequency, as well as providing some reserves to cope with further losses of generation. If the System Operator had not instructed the 1% reduction in demand, it is possible that the frequency would have fallen to a point where interruptible load was shed, or fallen further to a point where automatic load shedding would have disconnected about 16% of the North Island demand.

22 minutes after the GEN, the System Operator issued a Demand Allocation Notice (DAN) to 27 distributors and 8 direct connect customers, intended to allocate the overall 1% demand reduction limit equitably amongst the recipients. The DAN contained errors that allowed some recipients to increase demand above their original levels, but required 8 recipients to further decrease demand.

Several distributors suspected the DAN was incorrect due to the large amount of demand reduction and queried their regional Transpower National Grid Operations Centre (NGOC) or the System Operator's National Control Centre (NCC). Some queries were passed on to NCC, alerting controllers to problems in the DAN, and those distributors were asked to hold-off following the DAN.

However, 5 distributors queried their NGOC and had the instructions confirmed. Of these, 2 distributors (Electra and WEL) reported that they needed to disconnect additional consumers, equivalent to about 37 MW in total.

The System Operator allowed distributors to increase demand by up to 5% 1 hour 33 minutes after the GEN, and ended the Grid Emergency 2 hours 14 minutes after the GEN. Distributors reconnected consumers at varying times between the DAN being issued and about 15 minutes after the end of the Grid Emergency.

II. Root Causes

i. Root Cause of the Grid Emergency

The root cause of the Grid Emergency was a shortage of generation to supply the evening peak demand due to the combined effect of:

1) The lack of market pricing signals to provide sufficient commercial incentive to start-up either Contact's Taranaki Combined Cycle unit (377 MW) or Genesis' third Huntly Rankine unit (240 MW) in time to help supply the Monday evening peak demand.
2) 602 MW of generation capacity outages, 91% of these in the South Island.
3) The unexpected loss of 193 MW of hydro generation at Tokaanu, due to weed in the intakes, close to the time of the Grid Emergency.
4) The unexpected loss of 194 MW of wind generation below offers made from 3 hours before the Grid Emergency.

ii. Root Cause of Consumer Disconnections Following the DAN

The root cause of the additional consumer disconnections following the DAN was due to the combined effect of the following issues:

1) The System Operator's Policy Statement reallocation procedure for reduced demand is based on historical demands and is not appropriate for reallocating demand shed on a real time percentage basis, as occurred for this event.
2) The System Operator's procedure for managing demand is not consistent with the Policy Statement, as the procedure does not describe how the Load Shed Restore (LSR) tool is to be used to reallocate demand for a nation-wide peak capacity constraint. The System Operator instead used the tool as if managing a nation-wide energy shortfall.
3) The System Operator used out of date demand information from 2017 in the LSR tool, and incorrectly represented some industrial loads in the LSR calculation.
4) The System Operator failed to adequately sanity check the LSR results before issuing the DAN.
5) The lack of clear communications between the System Operator's NCC, Transpower's NGOCs, and distributors when handling queries about the incorrect DAN.

III. Recommendations

i. Slow Start-up Generators

Market pricing signals did not provide sufficient commercial incentive to start-up inflexible generators in time to meet the evening peak demand. The Investigator recommends that the Electricity Authority consider the relative benefits of the following suggestions:

1) If these conditions are expected to occur very infrequently, then make no changes to the existing market rules, and accept that demand management may be infrequently required when inflexible generators cannot start in time to make up for unexpected generation shortages.
2) Encourage a more elastic demand response to high prices. There may be a future opportunity here for aggregators to offer control of household batteries and EV charging.
3) Adapt the existing scarcity pricing mechanism to also cover scarcity of standby reserves. The scarcity pricing price floor and cap might improve revenue certainty for slow start expensive generators. This might be a relatively small change to the present market design.
4) Add unit commitment to the existing energy and reserve markets to give slow start generators the revenue certainty needed to start and run when there is uncertainty in the ability of generation to meet peak demands. This would be a significant change to the market design.
1) Create a market pricing signal for standby residual generation, additional to the existing pricing signals for energy and reserves (some might call this a short-term capacity market). This would be a significant change to the market design.

ii. Demand Allocation Process

This Grid Emergency was the first time the demand allocation process has been used after a nation-wide demand reduction. The demand allocation calculation in the Policy Statement is based on historical demands and does not appear to be appropriate for reallocating demand shed on a real time percentage basis, as occurred for this event.

The Investigator recommends that:

2) The Electricity Authority and System Operator review whether the demand allocation calculation defined in the Policy Statement, and implemented in the LSR tool, is fit for purpose for reallocating demand shed on a real time percentage basis.
3) The System Operator improves how demand allocation notices are sanity checked before being issued.
4) The System Operator improves training for the demand allocation process following island or nation-wide demand management events. This training should include joint exercises including communications between the System Operator NCC, Transpower NGOC, distributors, and retailers.

iii. Controllable Load

In principle, it is preferable to shed controllable load before disconnecting consumers. At present, the System Operator has very limited visibility of controllable load in the distribution networks. Better visibility will be needed to determine how much controllable load is available for shedding at any point in time.

The Investigator recommends that the Electricity Authority, System Operator, and distributors work together to improve the utilization of controllable load by:

1) Improving the System Operator's visibility of controllable load.
2) Formally agreeing that all relevant controllable load should be shed before disconnecting consumers. This includes shedding the controllable load of one distributor to avoid disconnecting consumers of another distributor.
3) Establishing processes for how the System Operator requests distributors to manage shedding and restoration of controllable load.
4) Considering the Upper South Island Load Manager (operated by Orion and visible to the System Operator) as a possible model for better utilization of controllable load.

iv. Wind Generation Forecasts

Offers of wind generation significantly over-estimated the amount of wind generation that could supply the evening peak demand. This was partly due to the use of a persistence model for forecasting wind offers 2 hours ahead.

The Investigator recommends that the Electricity Authority reviews the way persistence is currently used for offering or forecasting intermittent generation, and considers improving forecasting requirements for intermittent generation.

v. Public Communications During Incidents

The System Operator has a much better overview of system-wide incidents, such as this Grid Emergency, than other market participants. However, disconnected consumers direct their first queries at distributors and retailers who may not have ready answers to the situation and likely reconnection times.

The Investigator recommends that the System Operator improves the process for providing the public with timely and simple explanations for system-wide incidents, particularly where consumers have been disconnected.

vi. NCC Staffing and Training

Comprehensive training for rare events is limited by the amount of time that the coordinators can be relieved from desk duty while maintaining 24x7 coverage with the available trained staff numbers. Consideration could be given to increasing the System Operator's real time operations capability to provide a support function to manage external stakeholder communications during events. In addition to their primary roles of managing system energy and security, there are substantial demands on the skilled real time staff pool to provide subject-matter expertise into a variety of initiatives and capital projects.

The Investigator recommends that the System Operator reviews the staffing of NCC with a view to further enhancing its programme of continuous skills improvement, including simulations which stress test processes and rarely used tools, and to provide access to support during major events.

vii. Training Simulator

The training simulator environment offers the best opportunity to build technical skills and offer real time exercises including rare system events which can include industry partners. This simulator environment is a constrained resource as it is shared with personnel delivering projects.

The Investigator recommends that the System Operator reviews the adequacy of the training simulator environment for meeting the current and future needs of training coordinators, conducting real time exercises with industry partners, and accommodating the needs of ongoing project delivery.

viii. Industry Training for Rare Events

Training for rare events is a common problem for many industries. In this case, the NCC coordinators lack of familiarity with the LSR tool for nation-wide generation capacity shortages contributed to the incorrect DAN.

The Investigator recommends that the System Operator identify rarely used procedures, review the associated training requirements, and take leadership in maintaining industry competence in handling rare events.

Annex E: Review into Transpower Communications, 9 August 2021 Grid Emergency, Thompson and Lewis Report, 8 October 2021 – Recommendations

Full report available at: https://transpower.co.nz/sites/default/files/news-articles/attachments/Thompson%20Lewis_9%20Aug%2021%20Grid%20Emergency%20Investigation_Final%20Report.pdf

I recommend to the Transpower Board and management that the following matters be addressed.

a. The GM External Affairs and Corporate Communications Manager to continue its work to agree a communications protocol with key government stakeholders to ensure as much clarity as possible as to both the types of events that should be escalated and the information requirements at the point they are.

b. That Transpower policy GL-DP-008 Guidelines for Internal Communication During an Event or Incident be amended to specify that in the event of a Grid Emergency Notice (GEN) being issued due to anticipated insufficient generation, the GM Operations and Chief Executive are to be immediately notified by phone.

c. That a System Operator policy focused on communications with external stakeholders be developed. This could be based on the grid focused policy Event Response – Major System Event Policy.

d. That the Event Response – Major System Event policy be amended to make clear reference to both the Minister of Energy and Resources and shareholding Ministers being advised in a timely manner should a significant event occur to meet Transpower's "no surprises" obligation.

e. That the Process for Unplanned Outage Communications be amended to specify that in the case of significant events, the Chief Executive's approval for key messages is to be sought and obtained.

f. That in future security of supply situations, escalation both to the Chief Executive/Chair and to key government stakeholders be undertaken via phone rather than text/email.

g. In the event that significant security of supply issues either occur or could be reasonably foreseen to occur in the coming hours, the GM Operations and/or Duty GM should in a timely fashion pull together key management in an Incident Management Team (IMT) to focus on meeting the Board's and key external stakeholders information needs.

h. That through its government relations programme, Transpower External Affairs and Corporate Communications management continue to build ongoing relationships with key officials and the relevant Private Secretaries in Ministers offices to understand their information needs and make it easier to pick up the phone and make direct calls in times of need.

i. Noting that escalation issues involve judgment in times of not always perfect information, the System Operator and Corporate Communications teams should work together to develop an annual scenario practise session to help ensure readiness for future events.

Annex F: Electricity Authority Immediate assurance review of 9 August 2021 demand management event – Executive Summary

Full document available at: www.ea.govt.nz/assets/dms-assets/28/Immediate-assurance-review-of-the-9-August-2021-demand-management-event.pdf

Executive summary

1.1 The Electricity Authority (Authority) has used its statutory powers under section 16(1)(g) of the Electricity Industry Act 2010 (Act) to undertake an urgent review of the event on 9 August 2021.

1.2 The Authority's review has two phases. The first phase of the review sought to assure New Zealand consumers immediately that any systemic and process issues that led to the electricity cuts on 9 August are urgently corrected. In particular, the review was around:

(a) Transpower[17] as the system operator's communications with industry around the event of 9 August 2021.

(b) the system operator's load shed and restore (LSR) decision support tool used to generate the demand allocation and the processes and protocols associated with its use and maintenance.

1.3 This report provides the Authority's findings from phase one of its review.

What the Authority has found

1.4 On 9 August the country faced the largest New Zealand demand peak on record in response to one of the coldest nights this year. Transpower, as the system operator, was managing a situation in real time where dispatch and forecast schedules indicated all available generation had been dispatched, there was insufficient reserve available to protect the power system from a significant loss of supply and it was unable to manage grid frequency. The Authority acknowledges that the system operator's operations staff took immediate action under difficult circumstances to avert a potentially more widespread and longer duration event. This represented the first use of widespread, island-wide or national, demand management since the rolling blackouts of 1992.

1.5 The Authority has found shortcomings in the system operator's tools and processes. The key areas of concern were ambiguous and at times unsatisfactory communication processes and a miscalculation of demand allocation using the LSR decision support tool.

1.6 The review identified communication and operational issues including:

[17] Transpower has two parts to its business. As the grid owner, Transpower owns and operates the National Grid. As the system operator, Transpower is responsible for managing the real-time power system and operating the wholesale electricity market. This report focuses on Transpower's system operator role and accordingly where the term "Transpower" is used in this report it refers to Transpower in its system operator role.

(a) confusion among distributors as to whether some communications issued by the system operator about the 9 August event were instructions to act immediately or notices that action would be required later. This resulted in some distributors being unsure about the action required.

(b) limited stakeholder and customer communications as the communications from the system operator were, by necessity, operationally focussed and did not provide the context needed for distributors and retailers to share with their customers and communities.

(c) functional issues with the system operator's LSR decision support tool and the use of the tool during the event, including significant discrepancies between the allocated demand limits and the demand individual distributors and direct connect consumers were consuming at the time or were physically capable of consuming.

Communications

1.7 Clear communication is critical in an emergency. The Authority recommends an annual pan-industry contingency exercise to test processes, actions and communications and clarify responsibilities ahead of responding to a real emergency. To ensure effective communication during an emergency, the exercise should include testing of:

(a) operational communications between the system operator and distributors and direct connect consumers

(b) wider communications from the system operator to the electricity industry and key stakeholders including the Authority, officials and Ministers on the response and actions underway

(c) communication channels to support the cascade of information from distributors to customers and from retailers to customers.

1.8 The Authority has included other specific recommendations to support an effective communications protocol in the event of an emergency, such as an automated emergency notification system that does not rely on email communication.

Load shed and restore decision support tool (LSR)

1.9 The LSR decision support tool is used to calculate and equitably allocate how much load distribution companies and direct connect consumers need to shed and then restore if and when required to support a secure electricity system.

1.10 This tool is a decision support tool used by the system operator operations staff when managing a grid emergency requiring load disconnection in real time. The tool is not fully automated and requires manual setup to define the scale of the load management required. This is both in terms of the amount of load required to be disconnected and the geographical regions affected, and those distributors and direct connect consumers that will be required to manage their load. The output of the LSR decision support tool is a demand allocation notice, this contains a megawatt (MW) load setpoint that each selected distributor and direct connect consumer must limit their load to until further notice. This allows the system operator to stabilise the power system and determine any further action they need to take to return the grid to a secure operating state.

1.11 On 9 August, issues with the LSR decision support tool resulted in some distributors being instructed to disconnect significant numbers of consumers. At the same time, other distributors were issued MW load setpoints above their original load levels.

1.12 Following enquiries from some distributors regarding their demand allocation, the system operator suspended the use of the tool. Under the grid emergency management process, the LSR decision support tool would have been used to calculate an equitable distribution of load restoration for distributors and direct connect consumers. This would have resulted in a further demand allocation notice being sent that would have included the same calculation errors as the original allocation notice.

1.13 The 9 August event was the first time the 14-year-old tool had been used in a national event outside of annual system operator staff training. When it has been used previously, it has been for localised events involving a limited number of parties in the same geographical region.

1.14 The Authority recommends the system operator complete a review of the tool, and the information it relies on, to ensure it meets the needs of the current power system before a decision is made to reinstate it.

Key recommendations

1.15 The following table summarises the key findings and recommendations of this immediate assurance review. A full table of issues, actions and recommendations is in Appendix A. Transpower has two weeks to provide the Authority with a detailed plan in response to these recommendations (note Next Steps).

Table 2: Summary of issues and recommendations relating to the *Immediate Assurance review of the 9 August Demand management event*

Issue	Recommendation
Significant communication volumes and call durations to National Coordination Centre (NCC) staff added to the operational overhead in the control room	The system operator will further electricity sector readiness to respond to critical demand management incidents. This will include (but not be limited to) an annual pan-industry exercise - (similar to critical gas contingency incident management exercises). The first exercise will place emphasis on resolving the objectives of communications between the system operator and distributors and direct connect consumers.

Industry stakeholder and customer communications by distributors and retailers were limited by a lack of information regarding the event from the system operator	The system operator will work with distributors and retailers to resolve and formalise how priority information is to be promptly and consistently cascaded, and how affected customers and stakeholders will be notified for critical grid emergencies, unplanned outages, and material deterioration in network security. The system operator will put in place an agreed communication approach that will enable distributors and direct connect consumers to support a response to critical grid emergencies, in parallel to managing localised network support pressures.
The system operator had little visibility of actions taken, or planned to be taken, by distributors and direct connect consumers	The system operator will establish baseline information on the general demand management resources available within the system, and update this on a regular basis. In support of potential grid emergency responses, the system operator will establish processes capable of timely verification of the actual demand management resources available to the system operator, to the distributors, and to direct connect consumers.
There were significant discrepancies between the 19.09 allocated demand limits and the demand individual participants were consuming at the time, or indeed were physically capable of consuming	The system operator will put in place an assurance system that identifies the current state of the suite of decision support tools that are relied upon to respond to medium and large-scale events. The purpose is to ensure that the stock of tools is regularly maintained and adjusted to reflect material changes in networks. Specific to the LSR decision support tool, the system operator must determine if the LSR decision support tool continues to be fit for purpose.

The receipt of email notifications was not always noticed by the recipient operations staff	The system operator will evaluate alternative communications systems that would better support notification to the operations focussed staff that are the target recipients (separate to the current email-based notification approach). In the interim, where practicable, formal notices published using the existing email delivery approach which require timely recipient action should be followed up with phone calls. To support the current email-based notification, the system operator will put in place an assurance system to maintain up to date contact lists for key operational staff (and back up contacts) across distributors, direct connect consumers, generators and any other parties that could be required to respond to an emergency notice from the system operator.
Confusion as to whether notices were calls to immediate action or forewarning of possible future action	Where practicable, the system operator must ensure formal notices include specific actions to take, the reason, the timeframes when these actions must be taken and confirmation of when the action taken is required – supported by timely feedback from the system operator on the effectiveness of those actions.

Steps taken by Transpower since 9 August

1.16 The system operator has made improvements to its communication processes and associated protocols since 9 August. This was demonstrated on 17 August 2021 when Transpower, as the system operator, initiated proactive industry communications, a media statement and teleconference when a grid emergency occurred. This better reflects the Authority's expectations of effective communications and information exchange in the event of a grid emergency.

1.17 The system operator has also suspended use of the LSR decision support tool for island and nation-wide demand management events.

1.18 The system operator is rarely faced with the situation that requires consumer disconnection. The actions taken by the system operator on 17 August 2021 provides assurance to the Authority that the system operator has learned from the process and tool shortcomings exposed during the 9 August event.

Next steps

1.19 The Authority expects Transpower, as the system operator, to respond to the recommendations in this report to improve communications and processes for demand management events within two weeks of publication of this report.

Transpower's response must include a plan of action to implement the recommendations of this report.

1.20 While the system operator cannot guarantee supply under all circumstances, the Authority is confident that adoption of the recommendations outlined in this report will ensure the system operator's decision support tools and communications processes are better placed to manage future demand management events to minimise impact on consumers.

1.21 The Authority also notes there may be further recommendations in the Authority's phase two report that will contribute to improving any future demand management event.

Phase two review

1.22 The Authority also has the following activities under way in relation to the 9 August 2021 event:

(a) phase two of its section 16 review – scope and timing to be confirmed, but will be informed by this phase one review

(b) investigation into an alleged undesirable trading situation

(c) allegations of breaches of the Electricity Industry Participation Code 2010.

1.23 The Authority's phase two review will be broader than the system operator's response to the event. In particular, the first phase of the review did not consider any potential issues in market rules, settings or incentives related to the 9 August demand management event, nor did it consider the basis for unit commitment decisions of generators in the hours or days prior to 9 August.

1.24 The Authority has started gathering information for the phase two review and will be seeking industry input throughout the process.

1.25 The Authority expects to confirm the scope of its phase two review during September.

1.26 The Authority notes the Ministry of Business, Innovation and Employment (MBIE) has also commenced an investigation and the system operator is conducting its own review.

Acknowledgement

1.27 In preparing this report, the Authority worked closely with the system operator and interviewed a range of industry participants, including direct connect consumers, distributors, retailers and generators, to establish the facts and understand the response. The Authority thanks all of the organisations who took part in this review and notes the way all parties were quick to provide information and engaged openly and constructively.

Annex G: Recommendations of this Investigation

Performance of the system and system operator (section 3)

1. *We recommend that the EA amend the Code to ensure the equity rule is deployed only when ripple control and any other type of discretionary load available has been exhausted.*

2. *We recommend that the EA scrutinise its relationship with Transpower, perhaps with international input, with a view to holding Transpower more firmly to the rules and contracts that bind it. We believe the EA should report its progress on this recommendation to the Minister of Energy and Resources after six months. We invite the EA to engage with other regulators in New Zealand which successfully both support and regulate their industries.*

Wholesale market and supply side (section 4)

3. *We recommend that the EA seek to disallow persistence forecasting and require all wind generators to use acceptably accurate ways to make their offers to the SO.*

4. *We recommend that the EA explore afresh the market for cap products.*

Demand response and demand side participation (section 5)

5. *We recommend that the EA demand major users are able to offer an acceptable demand side response in the event of a short term generation shortage, and regulate if commercial arrangements are not reached in a short period.*

6. *We recommend that the Code must be amended so that the SO has real time, and acceptably accurate, awareness of discretionary load available from each EDB by winter 2022. We commend the Upper South Island load management programme as a starting point.*

7. *We recommend that the EA and the SO design and implement a new product to manage multi-hour shortfalls.*

8. *We recommend that a new ancillary service be given serious consideration as the first step in the life-cycle of this new product.*

Information and communications (section 6)

9. *We recommend that the EA and Transpower address the findings and recommendations in the EA’s Immediate Assurance Review report, and reports by PBA and Thomson Lewis (both commissioned by Transpower) as a matter of priority, with each immediately initiating a programme of work, co-ordinating where appropriate.*

10. *We recommend that the EA and Transpower should each be asked to provide quarterly updates to the Minister setting out progress until the systems are in place. The EA should undertake subsequent compliance monitoring.*

11. *Transpower should ensure that it henceforth reliably and promptly provide the 24/7 communications needs of the SO in generation emergencies.*

12. *Transpower should design and undertake pan-industry contingency exercises, monitored by the EA, sufficient to test processes actions and communications, and to clarify responsibilities in a generation emergency. Transpower should consider engaging the National Emergency Management Agency in designing communications policies for use in an emergency.*

13. *We endorse the recommendation of PBA Consulting that the SO should improve its process for providing the public with timely and simple explanations for system-wide incidents, particularly where consumers have been disconnected.*

14. *However, we add that EDBs will usually hold relevant information that the SO does not, and are therefore also obliged to establish communication protocols, by multiple means. Both the SO and EDBs should be proactively in touch with all retailers, and should have established and agreed systems to achieve that.*

15. *We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication in a grid emergency, and encode such arrangements where appropriate.*

16. *We recommend the EA work with the SO, EDBs, retailers and consumer groups to establish best practice arrangements for information provision and communication with medically dependent consumers in a grid emergency, and encode such arrangements where appropriate.*

17. *Noting that these arrangements may not be materially different from those applying in the above recommendation, we suggest the EA and industry also consider an education campaign to ensure medically dependent consumers are aware of the importance of having a personalised emergency response plan.*

Looking ahead (section 7)

18. *MBIE and the EA should demonstrate leadership in their respective roles in standard setting where it is in the public interest to harness emerging demand side opportunities.*