Winter Peak Innovation Pilot

Learnings and insights report

February 2024

Future
Energy
Development

Contents

Preface

The purpose of this report is to present the learnings and insights gained from the Winter Peak Innovation Pilot. The pilot sought to demonstrate that distributed energy resources in the form of residential solar batteries can be dispatched into the electricity market, via a Virtual Power Plant (VPP), to address winter peak events where the forecast capacity residual is tight.

This document aims to contribute to the development and implementation of greater innovation and collaboration across New Zealand's electricity sector to unlock the true value of distributed energy resources and its place in the future electricity system.

Pilot participants included solar-and-battery-as-a-service provider, SolarZero; New Zealand's future energy centre, Ara Ake; the electricity system operator, Transpower; and the Electricity Authority. Key personnel representing the pilot participants included:

- Pam Walklin, Head of Commercialisation, Ara Ake
- Dr Jono Barnard, Research and Insights Manager, Ara Ake
- Chris Otton, Manager Policy - Operations, Electricity Authority
- Eric Pyle, Director – Public Affairs and Policy, SolarZero
- Em Rushworth, Data Scientist, SolarZero
- David Katz, Market and Security of Supply Manager, Transpower
- Stuart Miller, Market Technical Specialist, Transpower

The report has been primarily authored by Ara Ake and has been reviewed by all pilot participants and by Dr Stephen Batstone, Secretariat of the Market Development Advisory Group (MDAG) and Chair of FlexForum.

Executive Summary

In recent years, the electricity sector has become increasingly concerned about the capacity of the power system to meet winter peak, especially as more intermittent renewable generation comes online to meet New Zealand's decarbonisation objectives. In late 2022, in response to the Electricity Authority consultation paper *Driving efficient solutions to promote customer interests through winter 2023*, a group of industry representatives proposed that the Electricity Authority introduce an ancillary service specifically focused on addressing situations of tightening the electricity capacity residual i.e. when forecast available generation is very close to forecast demand.

The Electricity Authority did not proceed with the submitted proposal, introducing other measures for winter 2023.

In May 2023, Ara Ake partnered with solar-and-battery-as-a-service provider, SolarZero, to develop a winter peak innovation pilot to determine whether distributed energy resources (DER), specifically residential solar batteries, can be aggregated, triggered and dispatched into the electricity market, specifically in response to low residual situations during winter peak events.

Working closely with the system operator of the national grid, Transpower and the Electricity Authority, SolarZero were successfully onboarded into Transpower's systems (within the bounds specified by the Electricity Industry Participation Code), such that their 10,000 batteries could be aggregated as a virtual power plant (VPP) at one Grid Exit Point (GXP) per island. The SZFlex VPP (SolarZero's marketing name for their VPP) could then be triggered to charge on the issuing of a low residual Customer Advisory Notice (CAN), which notifies of a future time where the difference between forecast available generation and demand is less than 200 MW, and then be available for dispatch into the electricity market if needed.

During the course of the 8-month pilot, there were no actual winter peak events that progressed past the CAN stage where SolarZero would have been dispatched, however testing proved that SolarZero's SZFlex VPP could be triggered to charge and, if needed, be available to be dispatched into the market during a low residual event. SolarZero were dispatched to the electricity grid four times as part of the pilot deliverables, providing a maximum power output of 26.5 MW AC over a two-hour period on the final test.

Looking to winter 2024 and beyond, following the success of the pilot, all pilot participants believe there is value in DER being part of winter peaking flexibility, however whether it is better suited to a commercial arrangement or as an ancillary service remains up for discussion, as there are benefits and challenges associated with both options. The system operator is expecting that the winter 2024 capacity margins will again be tight.

This pilot has demonstrated that DER is a valuable solution that can be used in the toolbox to address winter peak. As SolarZero and other DER aggregators grow, there will likely be a significant volume of untapped potential which could contribute to multiple challenges in the electricity system.

The key technical aspects to be considered in unlocking this potential include the need for:

- a market mechanism designed specifically for dispatching aggregated DER, and
- increased visibility of DER at both a system-level (Transpower) and distributor-level (EDBs) to prevent any unintended consequences, including shifting an issue to another part of the electricity sector.

Going beyond the technical aspects, a more important question is “Where in the system does DER deliver the most value?”:

- For a customer, DER such as the solar and battery systems used in this pilot have the potential to reduce their electricity costs (noting that all costs in the sector ultimately fall to the end customer), increase their resilience to grid/network disruptions, and could provide them with incentive opportunities if they allow their systems to be used by an aggregator for dispatch into market, to counter network or system constraints.
- For a retailer exposed to the market pricing, DER has the potential to reduce their customers’ load, requiring less generation to be purchased to cover their retail book, in addition to reducing high spot market exposure.
- Distributors can utilise DER flexibility to support constraint management and defer capital expenditure on their network.
- For the system operator, if the appropriate mechanisms are in place, DER can be used in instantaneous reserves or, as demonstrated in this pilot, as peaking flexibility.

Determining the best value stack for DER will require industry-wide engagement. This is crucial to unlocking DER’s true value and optimal place in the future electricity system, as is ensuring a robust regulatory framework is developed for DER participation. Such a framework, alongside innovative commercial arrangements and platforms could unlock the value of DER and provide confidence to the sector, in the reliability of DER to provide a meaningful impact in our electricity future, and a potential alternative to the traditional approach of building centralised infrastructure.

The pilot participants are committed to working together, and with other members of the sector, to further enable DER and other flexibility services to participate in the electricity system as Aotearoa continues along the decarbonisation journey.

Introduction

Over time, New Zealand's peak electricity demand has continued to grow and, as a result, more generation has been commissioned to meet this. The predominant form of new generation over the past 10 years has been intermittent renewables, whose contribution to addressing peaks is variable based upon the intermittent nature of these resources. When combined with the uncertainty of the market's commitment concerning slow-start thermal units, meeting peak is becoming increasingly more challenging and this is particularly apparent during the winter months when demand is at its highest. To mitigate this winter capacity risk, grid and system operator Transpower has been calling for greater investment in flexible power system resources such as DER, fast starting generators, grid scale batteries and demand that can reduce quickly when the power system is tight.

In December 2022, the CEO Forum, a group of companies led by the CEOs of major electricity generators, distributors, and Transpower, presented a proposal to the Electricity Authority (EA). This was in response to the EA's consultation paper, *Driving efficient solutions to promote customer interest through winter 2023*, to express their mounting concerns about the power system's capacity for winter 2023, and offered an option for consideration.[1] Their proposal outlined:

- the problem of the tightening of the generation residual,
- the lack of ancillary services to manage imminent multi-hour shortfalls,
- the case and design of an ancillary service, including the specific trigger and timing of the intervention,
- some initial Electricity Industry Participation Code (the Code) drafting suggestions to support the service, and
- thoughts on monitoring, compliance and mitigating the risk of market manipulation.

The EA decided not to progress this proposal due to "concerns it could have the unintended consequence of incentivising the withholding or withdrawal of resource from the spot market, be difficult to modify or remove once in place and was unlikely to be in place in time for winter 2023".[2]

Instead, a number of other initiatives were introduced to enhance market information on the need for winter peak flexibility including:[3]

- improved wind forecasting information,
- publication of sensitivity schedules and island residual information, and
- difference bids for discretionary demand management.

It is in the interest of all New Zealanders to develop solutions which will ensure that winter peaks can be met during the clean energy transition. It is also of interest to ensure the solutions adopted to address this issue meet the electricity sector's reliability need (without creating other unintended consequences or simply shifting the risk to other parts of the sector), while also addressing the EA's concerns and aligning with the other two corners of the energy trilemma – sustainability and affordability.

One potential solution, which both has minimal lead time and helps to reduce overbuild of infrastructure to address peak demand, is the use of innovation in the form of distributed energy resources (DER). DER can range from simple ripple control of domestic appliances such as hot water systems (which have been used in New Zealand since the 1950s),[4] to more recent innovations such as electric vehicle chargers or residential solar battery systems. Theoretically, when aggregated these systems have the potential to be simultaneously triggered and dispatched to the electricity grid as a virtual power plant (VPP).

To test DER as a potential solution, in May 2023 Ara Ake partnered with SolarZero, a New Zealand-based solar-and-battery-as-a-service provider with approximately 10,000 residential solar battery systems across Aotearoa under management, to develop an innovation pilot to determine whether DER can be aggregated and dispatched as a peak demand product. This was specifically in response to a forecast low generation residual situation (i.e. the tightening of supply and demand).

The purpose of this report is to provide an overview and detail the outcomes of the Winter Peak Innovation Pilot (WPIP) and socialise the learnings to other potential VPP providers in New Zealand and the sector as a whole, as we look to winter 2024 and beyond.

Pilot overview

The aim of the pilot was to test if DER, specifically residential solar batteries, could be included in a controlled dispatch system (where availability is triggerable upon a forecast low generation residual), where the system operator (Transpower) has full visibility and understanding of the resource available and is able to dispatch it when needed, to make an effective contribution to managing winter peaks.

The pilot simulated a market-integrated demand response capability that is ring-fenced to operating only as a last-resort shortfall mitigation tool. The primary benefit of this tool is providing emergency generation capacity on the system that may be used for balancing, where normal market dispatchable capacity is insufficient. Without additional demand response capability, the alternative is reduced system security, which potentially could lead to a grid emergency and involuntary load shedding.

The WPIP explored the full set of challenges involved in dispatching thousands of distributed energy resources to help meet winter peak and informs how DER could be brought into the wholesale market via a dispatch system (to the extent the Code and system operator dispatch systems currently allow).

Pilot participants and their roles

Four parties were involved in WPIP – SolarZero, Ara Ake, Transpower (system operator) and the Electricity Authority.

SolarZero has among the largest VPPs in New Zealand and is one of few organisations in New Zealand who could provide sufficient capacity of distributed battery resources to aid in meeting peak demand in winter 2023. By the end of the pilot, their aim was to demonstrate that their SZFlex VPP product is capable of providing up to 30 MW of additional power to national grid.[i, ii, 5]

Ara Ake's role in the pilot was as primary facilitator, bringing the relevant parties together across the ecosystem to initiate the pilot and facilitate it to completion (which included demonstrating the availability and delivery of up to 30 MW of dispatchable DER capacity across an aggregated VPP in the event of a low residual situation). This included bridging the funding gap, as there are currently no market mechanisms in place that incentivise VPP participants for making available and providing additional capacity to meet winter peak. The total funding provided by Ara Ake for this pilot was up to $4 million NZD with SolarZero contributing $10 million NZD and the other participants providing inkind contributions in the form of expert resources.

Transpower's role, as the system operator, was to inform the scope and design of the pilot so that it accurately targeted the challenge of winter peaks, as well as supporting the testing and validation of the service delivered by SolarZero. Given the system operator's role in ensuring normal market operation as required by the Code, Transpower also ensured that any activity associated with the pilot was supportive of (and not detrimental to) market and system operation during the pilot period, whilst also integrating delivery of the pilot with any existing market and system operation mechanisms and processes wherever possible.

Finally, the role of the Electricity Authority was to provide advice, guidance and clarification of the Code where needed, particularly in understanding how new provisions in the Code could impact the pilot and distributed resources more generally, in addition to identifying where amendments to the Code or guidance may be required moving forward. The EA also provided detail regarding how various dispatch platforms were intended to be used and guidance on which may be the most fit-for-purpose when considering the application to be tested in this pilot.

i 30 MW of DER was deemed to be significant by representatives of both the System Operator and the Electricity Authority when considering the pilot nature of this project. For context, at 0642 on August 9th 2021, a low residual was forecast between 1730 and 2000. At 1700, a 31 MW deficit was predicted between 1800 and 1900 and a grid emergency was announced at 1710, followed by involuntary load shedding between 1847 and 2115.

ii SZFlex is SolarZero's marketing name for their VPP.

Selected dispatch system

With respect to this pilot, there are currently five potential ways for market participants to offer capacity from distributed energy resources into the wholesale electricity market:[6,7]

- Dispatchable Demand: a regime which enables demand-side participants to compete with generators to set the spot price and be able to respond more efficiently to wholesale market conditions. Best suited to large consumers seeking better cost control (usually direct connect consumers), who are able to modify all or part of their electricity consumption at short notice.
- Dispatch Notification Load: a low-cost path to allow smaller scale aggregated resources to directly participate in the spot market, similarly to Dispatchable Demand. The owners of small-scale flexible load, such as EV chargers, solar and battery installations or commercial buildings, could use these resources to manage spot price exposure for their retailers.
- Dispatch Notified Generation: a lower-compliance form of market participation aimed at battery energy storage systems, or other generating units, where asset owners are not required to provide real-time indications.
- Difference Bids: a route to allow consumers or aggregators to signal their price sensitivity in the forecast schedules and assess the impact of their resources by comparing the non-response and price responsive schedule results. Difference bids are not binding and are not included in the dispatch schedules.
- Interruptible Load: an instantaneous reserve product which is used for the short-term management of frequency. Dispatched providers are compensated for their availability at the marginal reserve price.

Dispatch Notified Load (DNL) was chosen as the most suitable dispatch system for the pilot given the systems to be dispatched (residential solar batteries) fall directly within the system's targeted niche. DNL also aligned well with the project aims of requiring dispatch to be visible, automated and triggerable. In addition, both Transpower and the EA were interested in testing DNL as it was a new system with no prior participants and is the system expected to be used in the future to dispatch DER.

Importantly, DNL can consist of an aggregation of smaller loads (provided that the aggregation can be done by the participant).[8] This is required for SolarZero given their resources are distributed across many residential homes around the country. Aggregation was conducted on an island-by-island basis such that the SZFlex VPP could bid into the market via only two grid exit points (GXPs) to meet Transpower's 1 MW per GXP requirement. – Takanini (TAK0331) in the North Island and Stoke (STK0331) in the South Island. These virtual GXP locations were selected by the system operator.

Further discussion on the demand-side dispatch systems, including the caveats identified during the pilot of using DNL for DER, can be found in the section, *Was DNL appropriate for DER demand response?*

Selected dispatch preparation trigger

One of the key aims of the pilot was to ensure that the SZFlex VPP was appropriately integrated into the system operator's processes such that SolarZero's DER capacity would be available to be called upon only to target specific challenges associated with meeting winter peak. In order for this to occur, SolarZero require a trigger a few hours in advance to the low residual situation to ensure their battery systems are sufficiently charged.

The suitable trigger is a low residual Customer Advice Notice (CAN) - a document, both emailed to participants and published on Transpower's website, detailing an upcoming time period where it is expected that there will be a tightening of the generation residual. This tightening situation is defined by a time period where the forecast national electricity generation residual i.e. the difference between supply and demand, is less than 200 MW according to the latest Non-Response Schedule Long (NRSL).[iii] This can be issued up to 36 hours in advance of the forecast constraint.

Upon issuing these notices, the system operator (Transpower) typically asks participants to review the accuracy of their current energy and reserve offers (which, for example, can vary due to wind forecasts), and if accurate increase them if they have capacity. Transpower also requests for discretionary demand participants to submit difference bids an hour either side of the low residual period and to increase any transmission offers where generation may be constrained.[iv]

Figure 1 shows an example of the evolution of a projected generation residual over time following the issuance of a low residual CAN - the particular example used is the residual at 6pm on May 11th 2023. Figure 2, a similar chart detailing the generation residual at the same time two days earlier (6pm on May 9th 2023), also shows how quickly the projected residual can change, demonstrating the need for fast response solutions to manage winter peaks, especially as more intermittent renewables come online and fossil fuel baseload is decommissioned.

In the case of this pilot, the issuing of a low residual CAN is the signal to SolarZero to make their capacity available during the low residual period in the event other factors (such as increased load or loss of generation or wind) make their dispatch necessary to meet peak demand.

In addition to CANs published on Transpower's website due to an upcoming low residual situation, alternate triggers for SolarZero included a Grid Emergency Notice (GEN). A GEN is published within one hour of real-time when either a forecast deficit or a real-time deficit is seen after gate closure to avoid cascade failure of the national grid.[9] If subsequent offers and load reduction is insufficient to meet demand during the specified period in the GEN, distributors will be instructed to reduce load and customers may face a short term loss of power supply.

iii Non-Response Schedule Long is a forecasting methodology used by Transpower as the system operator to understand supply and demand in the New Zealand electricity market. This model is produced every two hours and extends up to 72 trading periods (36 hours) into the future. A difference of less than 200 MW in the Non-Response Schedule Short (NRSS) or Week-ahead Dispatch Schedule (WDS) may also result in a low residual CAN.

iv An example of a Customer Advice Notice for a low residual situation is provided in the Appendix.

Figure 1: The timeline of the forecast residual at 6pm May 11th real-time (CAN issued at 11am on May 10th 2023).

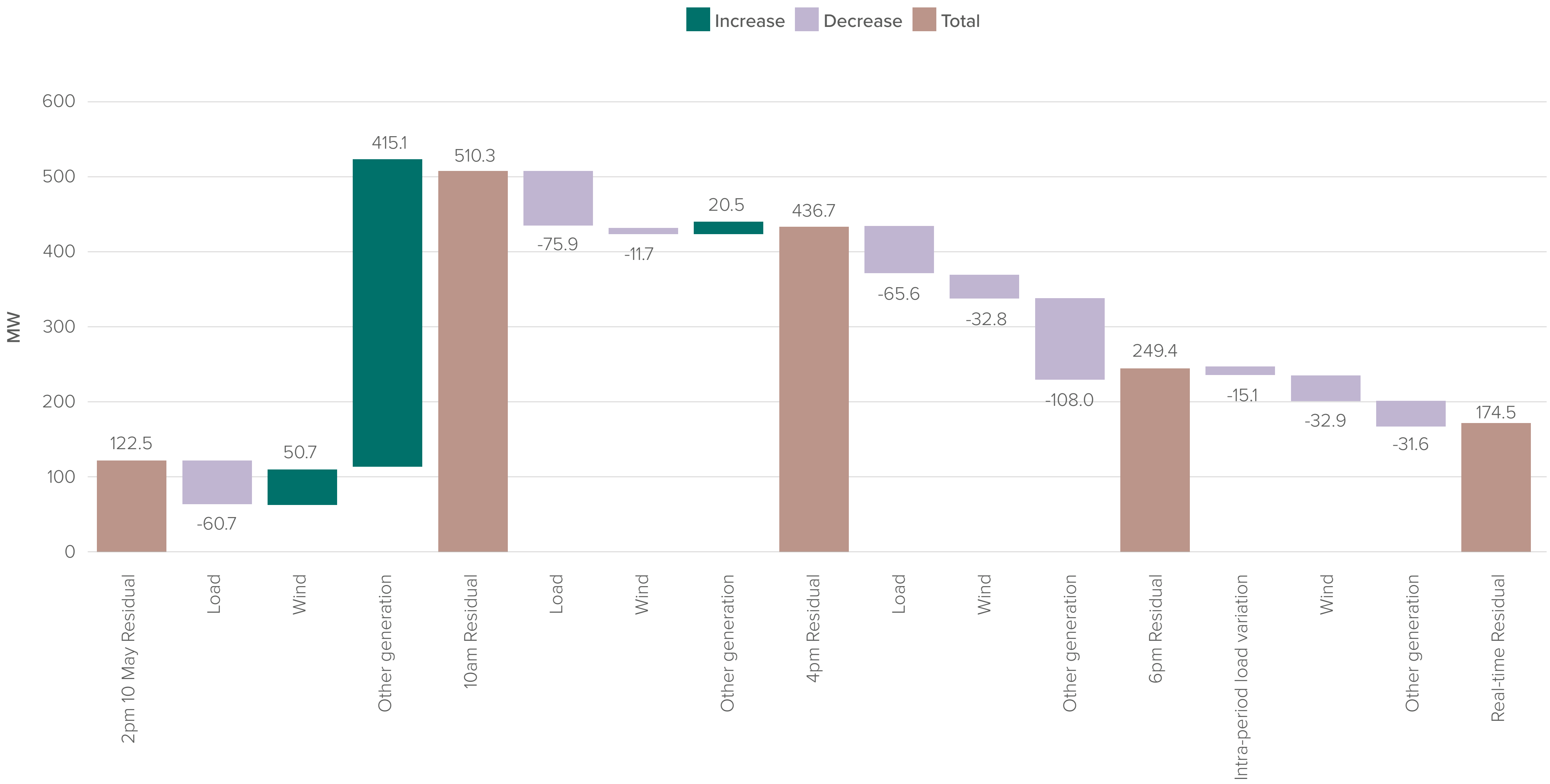
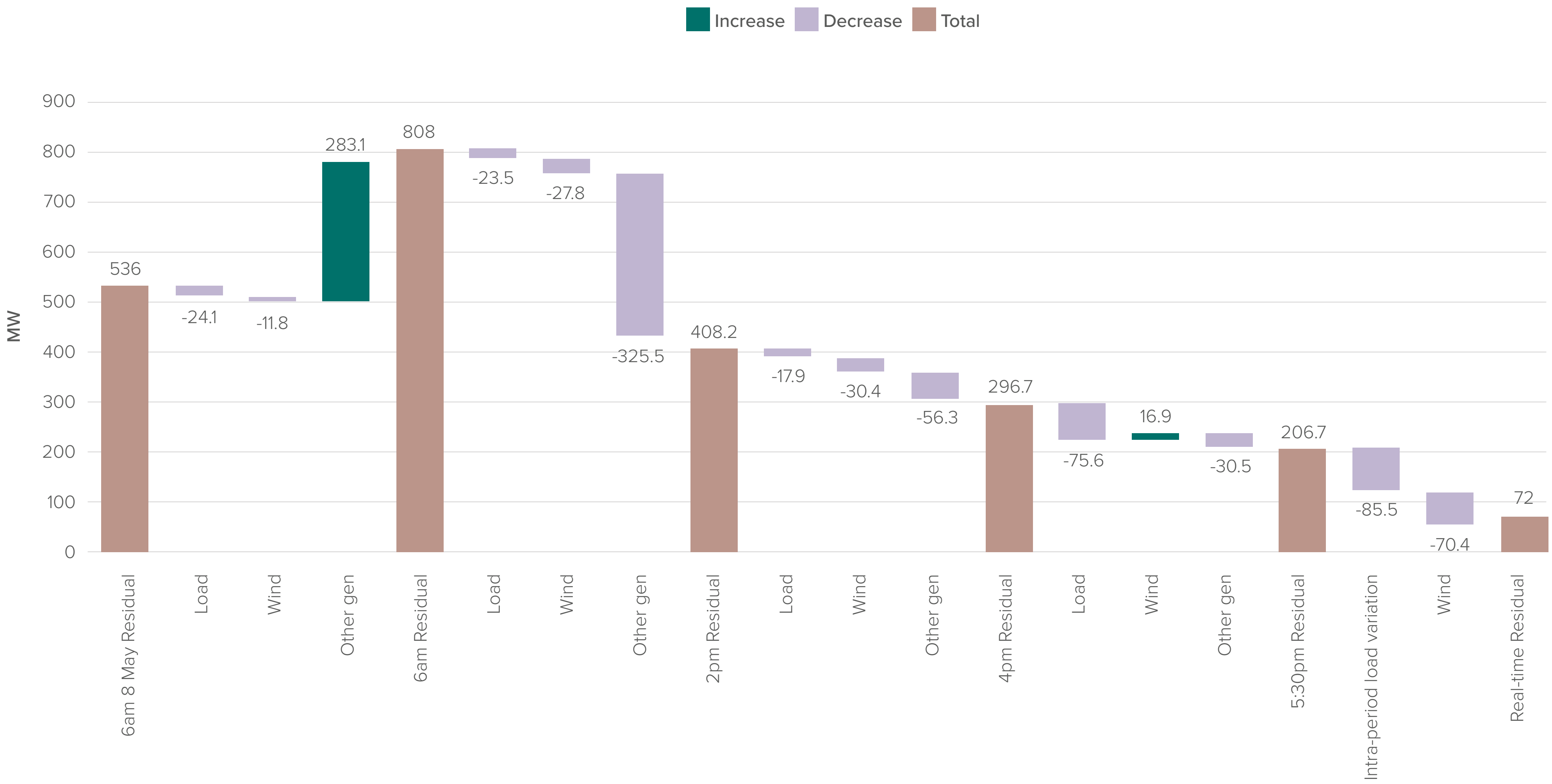


Figure 2: The timeline of the forecast residual at 6pm May 9th real-time. No CAN issued, but the residual dropped from an estimated 808MW 12 hours ahead of real-time to only 72MW at real-time.



Dispatch process

Upon selecting a dispatch system and gaining an understanding of the appropriate conditions to trigger the dispatch of the SZFlex VPP into the market, the following dispatch process was developed:

- Under normal conditions, the SZFlex system offers full capacity into the market via the Wholesale Information and Trading System (WITS), operated by the New Zealand Stock Exchange (NZX), but at a price high enough to minimise any risk of dispatch during normal market operations. The price selected for this during the pilot was $20,000/MWh (noting that the first tranche of energy scarcity is set at $10,000/MWh i.e. the price which is a result of instructed, involuntary load shedding).
- When a low residual CAN is issued by the system operator, SolarZero reads the notice to identify the period where the generation residual is tightening and prepares their battery systems to begin charging. The appropriate time to start charging their battery systems in order to achieve (or nearly achieve) 100% state of charge was typically two hours before the start of the forecast generation shortage period identified in the CAN.
- Prior to gate closure for DNL, 30 minutes before the trading period (a condition set by Part 1 of the Code) identified in the low residual CAN, SZFlex automatically updates the bids in WITS to reflect the total battery capacity available and to reduce the dispatch price from $20,000/MWh to $2,995/MWh. This trigger price was determined independently of the system operator (Transpower) and the EA, however was decided as suitable when considering the scarcity price bands set out in the Code.[v] Notably, to be consistent with market design and the current lack of market mechanisms in place, if SZFlex was dispatched at this trigger price, no market-associated payment would be received by SolarZero.
- During a peak event, if prices reach the trigger point, the system operator (via dispatch instructions) provides SolarZero with detailed instructions specifying the capacity required to be dispatched over a given period of time. Under DNL, there is potential for these instructions to change every five minutes (compared to forward scheduling which considers over the whole 30-minute trading period).
- During dispatch, the SZFlex VPP acknowledges the DNL instructions and actions them.
- Following the low residual period, SolarZero's systems would return to normal operation and WITS bids would be readjusted.

The above process is relevant when there is sufficient time prior to the low residual event, however following the issuance of a Grid Emergency notice (GEN), dispatch instructions would be sent to SolarZero at short notice and it was agreed that, due to limited charging time, the SZFlex system would respond with a 'best endeavours' approach using any available battery capacity at that given time.

For the above use cases, Transpower and the Electricity Authority agreed that this pilot and the dispatch process associated with it complied with the Electricity Code and no Code exemptions were needed. The process behind coming to this agreement is detailed in the section, *Engage the regulator early and often*.

v Clause 13.58AA in the Electricity Industry Participation Code 2010. Tranche 1 of the sustained instantaneous reserve contingent risk violation specifies a price of $3,000/MWh.

Pilot outcomes

Throughout the course of the pilot (May to December 2023), there were 11 low residual CANs issued by the system operator. In all cases, there was sufficient generation to maintain a large enough residual such that the dispatch price remained below scarcity levels (<$3,000/MWh) and the SZFlex VPP was not dispatched into the market to help support a peak capacity issue (however, SolarZero's batteries were charged and available for dispatch).

Despite not being dispatched for an actual low residual situation during winter 2023, between the dates of July 20th and December 8th 2023, Transpower sent SolarZero dummy low residual CANs and via DNL, dispatched a total of 144.5 MWh AC into the market from the SZFlex VPP (i.e. SolarZero's distributed batteries).[vi]

The four specific dispatches,[vii] conducted to achieve the pilot milestones, were:

- 18.5 MW AC for 1 hour from 7,494 batteries, starting 2.00pm on July 20th 2023,
- 23.6 MW AC for 1 hour from 8,565 batteries, starting 5.00pm on August 22nd 2023,
- 24.7 MW AC for 2 hours from 10,482 batteries, starting 2.30am on November 15th 2023,[viii]
- 26.5 MW AC for 2 hours from 10,787 batteries, starting 3.30am on December 8th 2023.

For comparison, during a typical winter peak period, SolarZero's batteries would be discharging to cover only a portion of the household load of their customers and would be net importing from the grid. Specifically, between 5pm and 7pm on weeknights in August 2023, the average household load across SolarZero's entire network was 11.9 MW AC with a battery output of 8.5 MW AC.

These tests could be validated using SolarZero's inhouse data management system, meter data from Ecotricity (the electricity retailer with the largest proportion of SolarZero systems) and the system operator's market monitoring system.

For example, Figure 3 shows the state of charge of a select few battery systems before, during and after the test dispatch on July 20th 2023. Upon observation, these systems can be seen to charge prior to the test, fully discharge during the test period (with the two-hour systems reaching a state of charge of approximately 50%) and then subsequently begin to recharge after 3pm. Ecotricity's data, measured at the meter of each household, aggregated and plotted on Figure 4 shows a significant peak of grid injection during the test time. Outside of the test period, injection measured at the inverter aligned with what would be expected for solar generation only. Figure 5 plots both the actual and forecast North Island electricity load data from Transpower's monitoring systems during the July 20th test period and a clear decrease of the order of 15 MW is observed at 2pm when SZFlex is dispatched into the market.

The validation of these dispatch events provides evidence that the pilot has demonstrated that DER can be aggregated, triggered and dispatched by the system operator and utilised in low residual winter peak event situation.

vi To ensure all battery systems were dispatched following receiving a dummy CAN from Transpower, SolarZero reduced the SZFlex price to $1/MWh. No market mechanisms were in place (which remains the case) to incentivise SolarZero for this dispatch.

vii In addition to these four milestone tests, a surprise test was conducted on September 18th where the system operator sent a dummy low residual CAN to SolarZero 3 hours in advance of the 'low residual period' to simulate a real-world winter peak event. The system operator noted that upon dispatching SolarZero, a ≈20 MW reduction was seen on their systems.

viii Note that early tests to discharge SolarZero's batteries had minimal solar impact at the inverter, hence were conducted during the day. Tests later in the year were receiving significant volumes of solar at the inverter, such that the batteries could not be proven to be discharging fully/be within SolarZero's control (because the inverter prioritises solar production over battery discharge), so testing was moved to the early morning prior to sunrise.

Figure 3: State of charge of four randomly selected SolarZero battery systems on July 20th 2023. The red dotted lines details the 2pm-3pm dispatch test period.

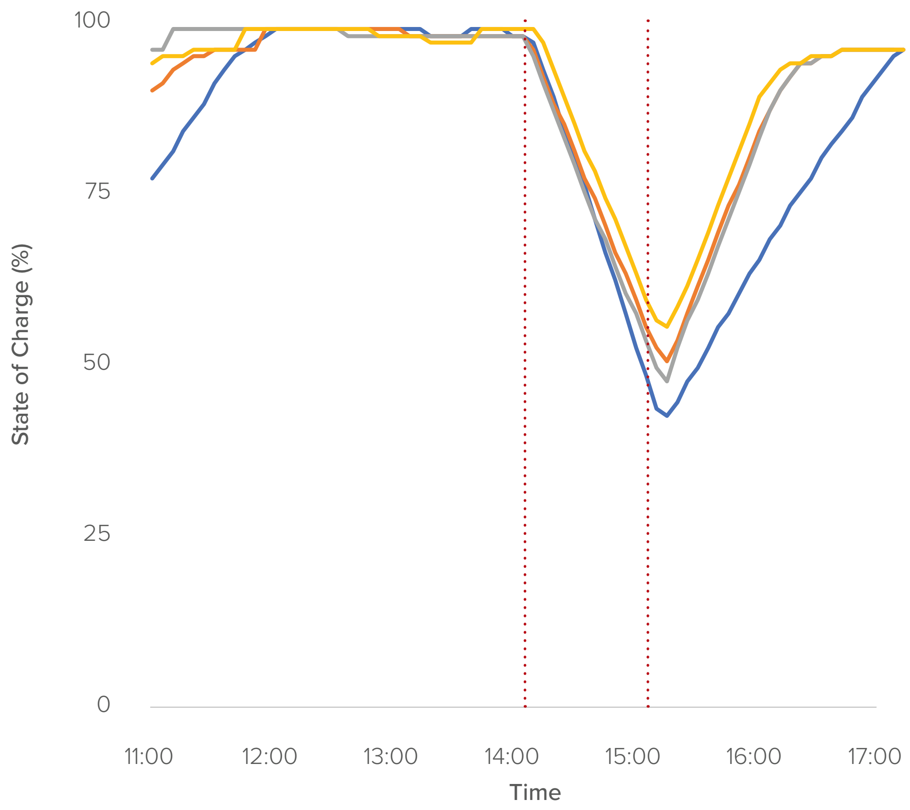


Figure 4: Ecotricity measurements of average grid injection of SolarZero systems on July 20th 2023. The red dotted lines details the 2pm-3pm dispatch test period.

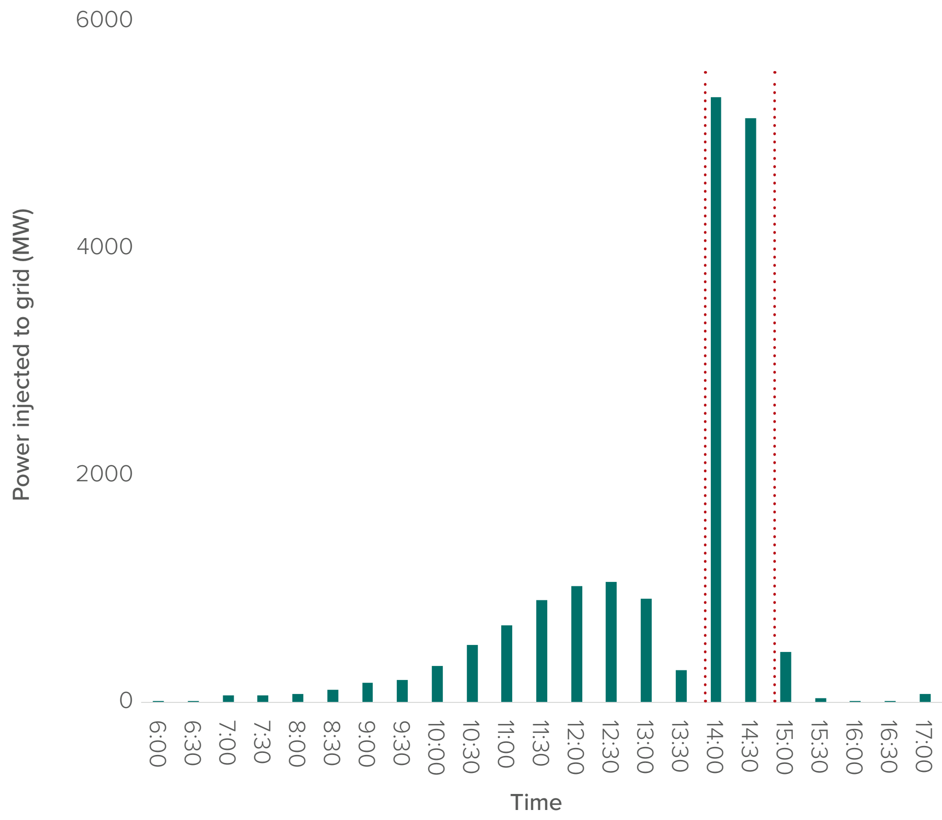
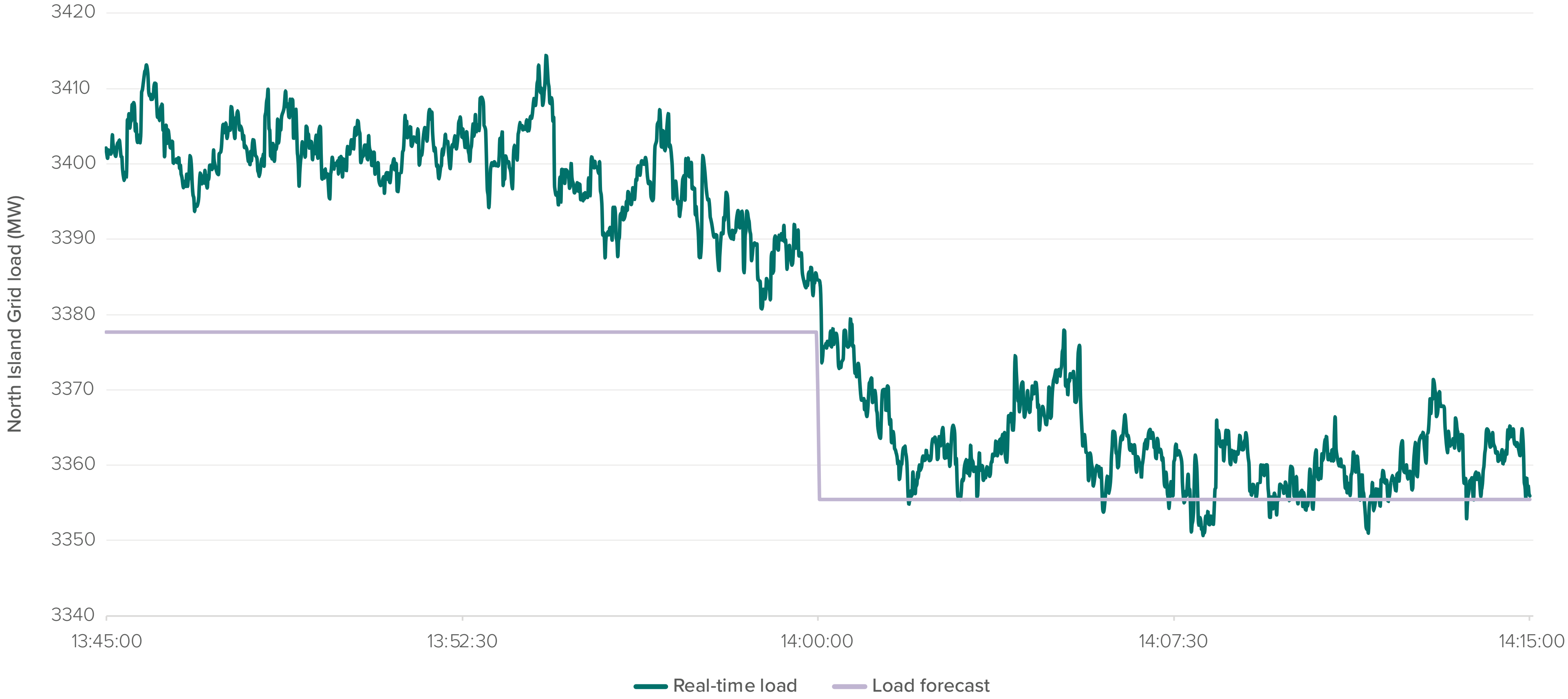
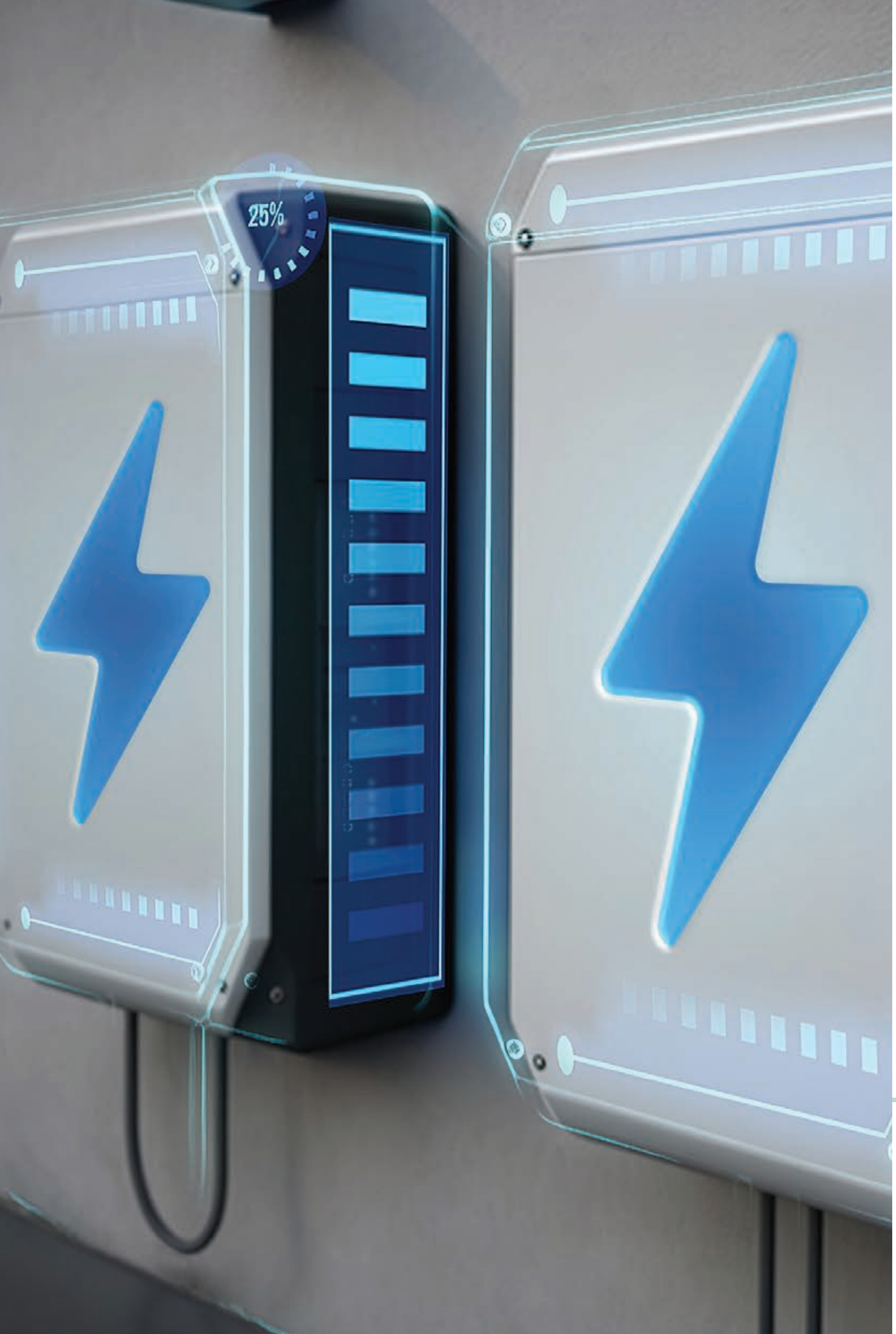


Figure 5: Real-time (actual) and forecast load measurements for the North Island at the start of the test period (145pm to 215pm) on July 20th 2023 from Transpower's market monitoring system.





Pilot learnings

All parties involved in the pilot consider the project a technical success, as it demonstrated that DER, specifically distributed residential batteries, can be both made available and dispatched into the electricity market by the system operator (Transpower) for low residual winter peak situations.

Although this was proven possible, there were a number of challenges that both SolarZero and Transpower overcame in order to put the pilot into practise. The following sections detail these specific hurdles and the lessons learned from the pilot in an attempt to streamline the process for future participants.

Complexities of putting a VPP into practice

Early into the pilot, it became clear that the technical challenges associated with dispatching DER were significant for both SolarZero and the system operator. In effectively a single step, the number of "generators" capable of being dispatched by the system operator increased from around 200 to 8,200.[ix] However, it is in the best interest of the system operator to minimise the number of systems for dispatch, hence SolarZero developed their internal systems to enable a single instruction per island from Transpower to dispatch thousands of residential solar batteries to the specified requirements.[x]

Enabling thousands of DER to appear to the system operator as a dispatchable power plant was a key part of the technical innovation of this pilot, as well as the source of most of the complexity. The main challenges for SolarZero which occurred during this pilot are noted in the following sections.

ix Although, at the start of the pilot, SolarZero had a fleet of 10,000 batteries, only 8,000 of those batteries had the software capable to be controlled by SolarZero to respond to dispatch instructions from the system operator. Software updates were completed throughout the pilot in order for SolarZero's entire fleet to participate in the VPP.

x As part of DNL, the system operator sends GXP-level dispatch instructions to each registered participant. During this pilot, SolarZero aggregated all their DER to a single GXP per island, so as a result, only received a single dispatch instruction per island.

Accurately controlling the discharge rate

Of the distributed battery resources across New Zealand under SolarZero's control, the systems fell into one of three rated capacities: 5.4kWh, 6.3kWh or 10.8kWh. For this innovation pilot, the discharge rate of these three battery types needed to be set in relation to the duration of the dispatch event (as specified by the low residual CAN), but also be capable of significantly varying their power output to match the system operator's specific five-minute instructions (which is a DNL requirement).

This created complexities as the power and duration (energy) capabilities of the battery systems would not necessarily match the duration required by the system operator (notably, dispatch instructions can potentially vary every 5 minutes). The varying age of each system also meant having the same rated capacity, the actual achievable output of each system varied on a case-by-case basis due to the battery's state of health.

For the above reasons, SolarZero needed to control the discharge rate of each individual battery system in order to achieve a given output across the entire test period. This required individual schedules to be created and sent to each battery across the 10,000 system fleet, potentially in response to a dispatch signal that could vary the dispatch amount every five minutes.

Developing the software for this dispatch system proved complex, as rather than simply sending a generic instruction to all the systems, the instruction for each battery system needed to be calculated using the latest data available in order to ensure that the aggregated bid was accurate.

It is SolarZero's position that if an aggregator is to participate in the electricity system to the level of accuracy required by the system operator, each system associated with the aggregation would need to be individually controlled. The system operator's view is although a level of accuracy is required, the benefit of aggregation is that a number of individual systems may over- or under-perform, but these will have little impact on the average output across all the aggregated systems.

At present, it is understood that some demand-side aggregators who offer into the reserves market use statistical analysis of their portfolio to determine an aggregate offer level that they are confident they can provide. This may sacrifice some of their offered capacity, but significantly simplifies their control systems. A similar statistical methodology could be taken for a VPP to bid into energy market as an aggregator can't always be fully confident the maximum capacity they have available will be delivered *(see Voltage limitations)*.

Voltage limitations

For the latter stage of the pilot, due to the time of year when these tests were conducted, solar generation distorted the results and a decision was made to move testing to the early hours of the morning. This, however, led to testing issues with respect to distribution level voltages.

Typically, overnight distribution level voltages across the country are high due to low loading and when a residential battery discharges, the system voltage measured at the inverter tends to increase. In some cases, the system voltage can reach levels where battery output is limited under standard *AS/NZS 4777.2 - Grid connection of energy systems via inverters, Part 2: Inverter requirements* in order to stay within operational limits – 230 V +/- 6%.

SolarZero inverters have two versions of *AS/NZS 4777.2* installed throughout their fleet (depending on when the inverters were installed). These standards are from either 2015 or 2020, and have different voltage limits:

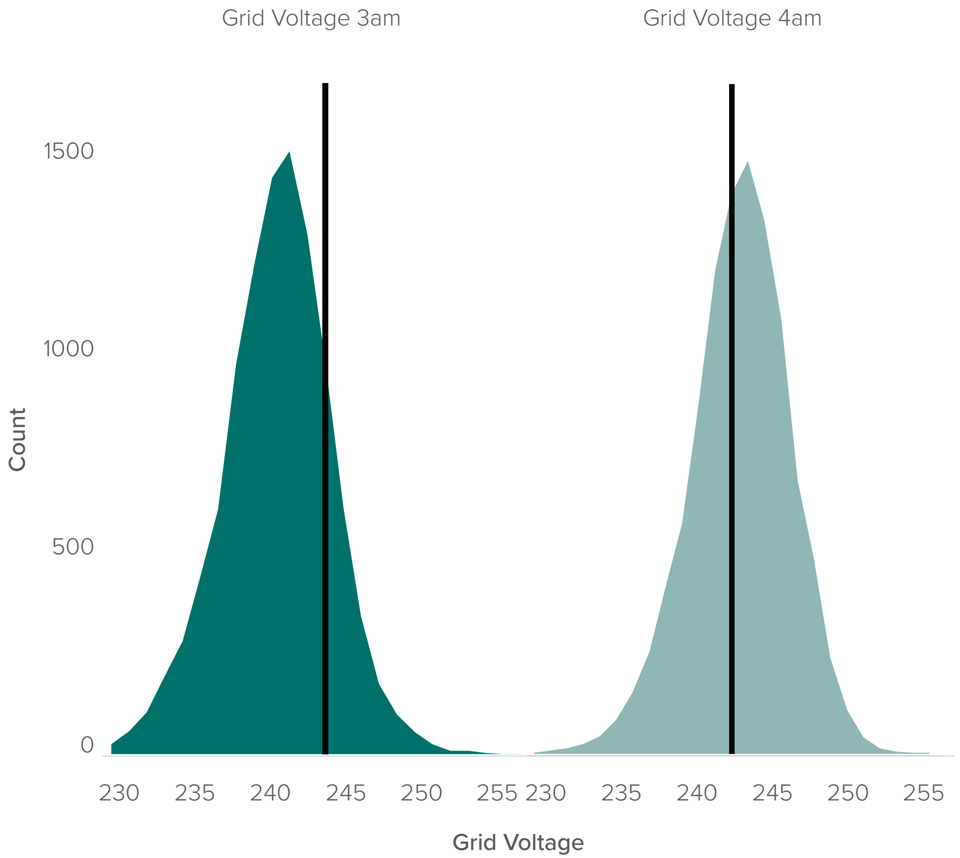
- 2020: Volt/var response (the reduction in reactive power) begins at 235 V and volt/watt response (the reduction of real power) begins at 242 V.
- 2015: No volt/var response and volt/watt begins at 244 V.

Under normal loading circumstances, the systems will typically be operating above 235 V when discharging and the inverters under *AS/NZS 4777.2:2015* will be in volt/var mode. If the system voltage increases above 242 V, real power output will reduce linearly from 100% to 20% of the maximum at 250 V. Above this voltage, the inverter will trip, temporarily preventing additional power output.

Figure 6 shows how inverter voltages across the fleet shifted during the December 8th test. Prior to the test, at 2am, the average voltage across the fleet was 240 V. At 4am, 30 minutes after the test began, the average voltage increased to 244 V, exceeding the volt/watt response threshold for the *AS/NZS 4777.2:2015* inverters and equalling the volt/watt response for the *AS/NZS 4777.2:2020* inverters. Across the entire fleet, over 7,000 batteries experienced a reduction in output due to this standard, resulting in an approximately 8% decrease in real power output.

Despite expecting an increase in voltage during the December test (as the same phenomenon occurred previously), it proved to be challenging to estimate both the voltage rise and the subsequent level of power curtailment. Systems that are comparatively far from the distribution transformer see low voltage levels before a discharge event begins, however observe a much higher rise in voltage than systems close to the transformer. As a result, ambient voltage before a discharge event proved to be a poor indicator of the curtailment and SolarZero are still investigating how to predict the actual output they will achieve in the event of voltage-related issues.

Figure 6: Fleet inverter voltages before (left) and during (right) the 8th December test. The solid line represents the start of the volt/watt response (the reduction in real power) for inverters operating under *AS/NZS 4777.2:2015*.



Going forward, if DER is to be used as, or part of, a winter peaking mitigation tool, testing during a winter peak period is required to help identify the level of voltage rise that can be expected during such an event. As demand is high during a winter peak, it is expected that voltage rise during a discharge event will be less than that experienced in the pilot during early morning testing. However, the actual amount of voltage rise and any associated power curtailment does need to be confirmed during winter peak conditions to ensure that any capacity specified in dispatch instructions can be met by a VPP, in compliance with *AS/NZS4777.2*, in the event of a low residual situation.

Administrative complexities

Ensuring code compliance

Despite certain sections of the Code being permissive in regard to the pilot (see *Engage the regulator early and often*), there were other clauses which SolarZero were required to meet in order to prevent Code breaches. One particular example of this was adhering to the following clause:

> ***15.5A Dispatchable load purchaser must prepare dispatchable load information***
> *(1) Each* **dispatchable load purchaser** *must prepare* **dispatchable load information** *using* **volume information** *prepared in accordance with Schedule 15.2.*

This was met by providing the reconciliation manager at NZX reconciliation files in relation to the SolarZero DNL bids, despite their being no incentive for being dispatched.

These files were typically vectors full of zeroes and as a result of this pilot, the EA identified that this clause could result in *“additional costs to participants and therefore limit participation”* and proposed that the user of dispatch notification *“would not be subject to the same reconciliation requirements that apply to dispatchable load purchasers”* in their consultation paper, *Dispatch notification enhancement and clarifications.*

Customer aspects

During the pilot, as a result of the significant amount of testing which was undertaken, a small number of customers (around five per test) contacted SolarZero to enquire about changes with the performance of their battery. A small proportion of SolarZero customers are vigilant and carefully observe what their systems are doing, however it is likely that if a small number of customers went to the effort of contacting SolarZero, the number who actually noticed the testing is far larger (although just how large SolarZero cannot be certain).

While SolarZero informed customers by email that they were doing testing, the customer service team still fielded queries on the topic. This was a learning experience for SolarZero as some customers wanted to discuss what was happening in detail and some communication aspects were not trivial. Overall, the main customer issues SolarZero experienced were of perception and this is a learning which SolarZero is going to account for when using their VPP in the future.

In regard to customer benefits for SolarZero using the energy stored in the batteries for the SZFlex VPP, rather than further reducing their electricity bill, SolarZero has included a VPP credit in its customer contracts.

This credit is a rebate that reflects the revenue that SolarZero considers it would reasonably earn from enabling the batteries and inverter to offer into reserves, winter peak or other ancillary service markets. This rebate has been set based off reasonably foreseeable revenues that SolarZero can expect to earn from its VPP's participation in the market over the twenty-year agreement with its customers.

This rebate has been included in its customer contracts to ensure that SolarZero maintains its commitment that any customer with a SolarZero system will save money in relation to what their electricity costs would have been without a SolarZero system.

Engage the regulator early and often

One of the key lessons in this project was to bring the Electricity Authority into pilot conversations early as they can clarify any Code related queries and perceived roadblocks. In this pilot, the inclusion of the EA significantly accelerated progress, as demonstrated in the example below.

As is discussed in *Selected dispatch system*, DNL was designed as effectively Dispatchable Demand for small load stations (1 – 10 MW) where the participant would be able to react to changes in spot price and better control their costs. This pilot, despite utilising this platform, was testing a use case significantly different from that initially intended.

As part of SolarZero's DNL application, in accordance with the Code (Schedule 13.8), they were required to apply to the system operator to become a dispatch-capable load station (DCLS) - an electricity-using device or group of devices that is capable of being dispatched. During this process, there was a concern that the following clause in the Code would require an exemption due to SolarZero aggregating their DER across the country to bid into the market as a VPP via two GXPs:

> ***13.3A Approval process for dispatch-capable load stations***
> *(1) A* ***purchaser*** *at a* ***GXP*** *may apply to the* ***system operator*** *for approval for a device or a group of devices at the* ***GXP*** *to be a* ***dispatch-capable load station*** *under Schedule 13.8.*

However, the EA made it very clear that Code changes/exemptions are the last resort, and that the Code is permissive so there may be scope to be flexible if the Code doesn't explicitly exclude certain scenarios. This led to the system operator writing a letter to include with SolarZero's application detailing the following:

> *"...the Code seems to anticipate a separate DCLS at each GXP, whereas SolarZero will be an aggregator at multiple GXPs across the country. Requiring a separate DCLS to be set up at nearly every GXP across the country would place a heavy burden on modelling...particularly, considering many of the GXPs would have a capacity of less than 1MW.*
>
> *Accordingly, we propose that SolarZero be setup as an aggregated dispatch notification purchaser at a single nominated GXP in each island. The total volume of dispatchable load in each island would then be traded at the nominated GXP in that island.*
>
> *...We believe this approach is the most practical way to support SolarZero into the dispatchable load market."*

In response, the EA specified that:

> *"Resources should be physically at the GXP they are bid at, however since the Code doesn't explicitly disallow DNL aggregation, we don't have any current objections to the system operator proceeding with this application in accordance with the reasoning set out in your letter."*

Without working directly with the EA, the pilot team would have likely interpreted the Code differently and may have begun investigating the exemptions process. This would have had a significant impact on the pilot timeline and the VPP would likely not have been demonstrated during winter 2023.

Notably, this letter also led to a full consultation, *Dispatch notification enhancement and clarifications*,[10] and resulted in a number of industry responses (discussed further in *Potential network impacts and constraints* and *What needs to change to incentivise other DER aggregators to provide winter peak services?*). Discussions with a representative from the EA detailed that initiating this consultation was where a lot of the pilot's value was for the EA, as despite the time and effort put into designing DNL (first introduced as *Dispatch-lite* in 2017),[11] certain aspects, such as the aggregation of distributed demand-side resources, was not initially considered. A change to the Code has been made following SolarZero's utilisation of the DNL platform and this is a clear example of the value of learning by doing.

Was DNL appropriate for DER demand response?

Although there are a number of options for demand-side dispatch, DNL was the only route which could be realistically taken to ensure the pilot could achieve its goals for winter 2023. However, using DNL alerted the system operator of the potential risks associated with aggregating DER (see *Aggregation constraints*). Despite being dispatched similarly to generation, DNL is fundamentally different as it was designed to be used by small, aggregated load stations, capable of reducing some load to enable other load to be served by generation, bidding at the GXPs that they're physically located behind, rather than by thousands of aggregated DER being bid at a small number of GXPs.[8]

The systems available to be used for demand-side dispatch, and by extension the Code, have not been designed for DER to participate in the wholesale market at the level of aggregation achieved in this pilot. Although using DNL in practice with aggregated DER has its challenges, it is currently the only option where VPPs can participate in automated dispatch, which is permissive to the Code.

The key constraints identified during the pilot associated with using DNL to dispatch DER are detailed in the following sections, along with the reasoning for selecting it as the preferred dispatch approach.

Aggregation constraints

In documentation on DNL, the system operator specifies "a limitation of 1 MW or more for dispatchable resources as a practical measure – given the amount of effort required to register a new market participant, plus the ongoing operational effort to verify dispatches for each node". The system operator also notes that "DNL load can consist of an aggregation of smaller loads, provided that the load aggregation is done by participant".[8]

Given the above, the agreed approach for the pilot, following consultation with the EA, was to aggregate SolarZero's 30 MW of capacity across two GXPs, with 24 MW associated with Takanini (TAK0331) in the North Island and 6 MW associated with Stoke (STK0331) in the South Island.

This virtual aggregation to two GXPs rather than SolarZero aggregating their assets on a locational, nodal basis[xi] significantly reduced the system operator's modelling requirements, whilst also providing a capacity per GXP over the 1 MW limit. However, as part of the pilot, the system operator identified that whilst they *"would enjoy a small operational benefit in only modelling load aggregation at a single nominal GXP* (in this pilot's case, two GXPs), *this benefit does not outweigh the operational risk of misrepresenting the location...within the nodal pricing solution*."[12]

In their response to the EA's consultation paper, *Dispatch notification enhancement and clarifications* (which was issued as a result of this pilot; see *Engage the regulator early and often*),[10] the system operator noted:

> *"The System Operator's tools to maintain system security are designed around the nodal market model (and) enabling aggregation of nodes into a nominal GXP is likely to lead to workarounds...which comes with associated costs in implementation and increased operational risk (because) aggregation across multiple GXPs does not reflect how we model the power system.*
>
> *...Applying aggregation across multiple GXPs as a workaround will almost certainly cause confusion for both the System Operator and load aggregators, which could ultimately create operational risk, if the level of misallocation of aggregated load becomes significant."*

As a solution to the nodal-visibility problem described, the system operator posed that their preferred solution was to "require all dispatch notification purchasers to bid at a nodal level irrespective of size" or alternatively, require all demand-side participants with a size equal or greater than 1 MW at a single node to bid at that single node, whereas other participants with less 1 MW at a single node(s) are permitted to aggregate at a nominal node up to a total of 5 MW as long as a region-to-node allocation factor is determined to enable better modelling at the nodal level.

For comparison, SolarZero's response to the EA consultation as the load aggregator and operator of the SZFlex VPP stated:

"For aggregators with thousands of systems, it is impractical to offer the unaggregated set of resources at each GXP. Bidding at each GXP when you are offering thousands of devices is potentially a major challenge and barrier to entry."

The challenge specified here is one of accuracy when considering offers to the market due to the phenomena of large numbers. For example, it is easier for SolarZero to confidently offer 3.6 MW from 1,000 3.6kW residential batteries compared to offering 36kW from 10 systems, as a spurious error in a single system has the potential to impact each offer by 0.1% and 10% respectively). This challenge was simply overcome during the pilot by SolarZero offering its systems at a single GXP in the North Island and in the South Island. Due to this approach, SolarZero has not run tests on a smaller number of systems (say aggregated to 1 MW), and therefore cannot be certain of the bid accuracy associated with aggregating DER to this magnitude.

SolarZero also believe that developing a multi-nodal approach increases the complexity of bidding, despite bidding complexity being something that DNL is trying to reduce. It is their expectation that the increased level of complexity, such as the requirement of receiving more than one dispatch instruction per island, would require an aggregator to have a greater level of experience and sophistication, potentially leading to additional barriers to entry.

Assuming there is value in DER being dispatchable to market (see *Is there value in a winter peaking product?*), the relative trade-offs need to be agreed between VPP operators, the system operator and the Electricity Authority (as the Code specifies the setup and operation of the electricity system), in order to enable DER capability to be realised for future years.

xi SolarZero systems feed into almost all GXPs across New Zealand.

Alternatives dispatch options considered

The alternative options considered for this pilot included dispatch notified generation (DNG) and difference bids.

Dispatch Notified Generation

DNG enables small-scale generation to participate in dispatch, whereas DNL is for smaller purchasers to participate in dispatchable demand. Due to the pilot being associated with residential solar batteries, DNG was initially the preference for the pilot as these batteries are effectively providing additional generation and cannot be considered as a load station capable of reducing its demand.[xii] Despite this preference, DNG has a significant number of hurdles which the project team believed would not be overcome in the time period for the pilot.

The main hurdle is that under Schedule 13.8 in the Code, Approval of dispatch-capable load station, clause 13.1 states that “purchasers are approved as dispatch notification purchasers”, and “generators are approved as dispatch notification generators.” This means that DNG participants must be registered as generators.

Doing so would in turn require that SolarZero sells any electricity which it generates to the WITS clearing manager under clause 14.3, Sale by generators with point of connection to grid, as well as submit reconciliation information monthly regarding the traded volumes for each ICP under their control, as per the definition of reconciliation participant in Part 1 of the Code.

In neither of the above cases is DNG differentiated from generation, however such differentiation does occur in other sections of the Code, such as clause 13.136, Offered embedded generation to provide half-hour metering information, where DNG is explicitly excluded.

In addition to generator complications, Part 1 of the Code only mentions aggregation in regards to purchasers (users of DNL), not generation (users of DNG) and this was crucial in the decision-making around the suitable dispatch platform to use, given the requirement of aggregation when considering the dispatch of thousands of distributed energy resources.

The pilot team believed that, although the EA were permissive with Code interpretation to allow SolarZero to become a DNL participant for the purpose of the pilot, it would have been unlikely the same permissions to have been granted for DNG, due to the additional co-ordination required from all parties involved including the WITS Clearing Manager and Reconciliation Manager.

Saying this, despite all the barriers described above, if there were no time constraints on the pilot, it is likely that the team would have sought Code exemptions to enable SolarZero to become a DNG participant rather than going down the DNL route.

Difference bids

Difference bids were only briefly considered for the pilot as the process has minimal automation and the system operator would have little control over the dispatch process. Upon receiving a CAN, SolarZero would submit difference bids an hour either side of the time period identified in the low residual notice. If dispatched, SZFlex would shed load (and also increase generation) for the entire time period of the difference bid. In comparison, DNL provides automatic dispatch instructions from the system operator every 5 minutes, detailing the load required to be shed over a given time period. Despite the lack of control and automation, difference bids was second choice for the pilot, in the case of not being able to overcome DNL’s Code challenges (and due to the fact that DNG was not a reasonable option in the time available). If difference bids became the only option, it is unlikely that pilot support would have been required as the appropriate market settlement mechanisms already exist and support from other pilot participants would be unnecessary.

Potential network impacts and constraints

Throughout the project, there was interest from the pilot participants on the potential impact of dispatching significant volumes of DER on electricity distribution businesses (EDBs), who operate on the low voltage network where the vast majority of DER is connected.

Discussions during the pilot touched on the potential for flow reversal due to large DER injection, which has the potential to damage transformers and other grid infrastructure, as well as the charging and discharging of batteries resulting in both capacity and voltage risks for EDB’s, as well as the potential to shift the residual shortfall time period forward.[xiii]

xii The SZFlex VPP can be almost treated as both additional generation and load reduction as discharging the residential batteries reduces household load whilst also providing additional generation to the grid. Despite the overall capacity being known, the relative portions of load reduction and additional generation vary depending on a range of factors including household load, time of day etc.

xiii Although these are all real concerns, the likelihood of the occurrence of these issues during the pilot was low due to the small volume of DER injection relative to the network size. The risk of these issues will increase as more DER capacity is introduced and offered into market to address winter peak or other system/network constraints.

An issue identified during testing was battery recharging times following the test, to ensure that no unnecessary strain was put on EDBs and their distribution networks. SolarZero's control system is programmed to ensure the batteries will not charge from the grid during peak times to prevent this risk. As a result, during a real winter peak event, this is not expected to be an issue as SolarZero would recharge their batteries well after the event (assuming that the low residual occurred during the morning or evening peak).

In response to the EA consultation paper, Electricity Networks Aotearoa (ENA), an industry group representing New Zealand's 27 EDBs, specified that they support the participation of small-scale resources, such as residential solar and battery systems in the wholesale market, however their highest priority is ensuring the safe and reliable operation of their distribution networks:[13]

> *"As more consumers' distributed energy resources (DER) are managed in response to wholesale market signals, EDBs need visibility of the individual resource participating in the dispatch notification process, its location on the network and the aggregator that controls that resource.....Awareness of the future likelihood and potential risks of DER "herding" (i.e. large quantities of DER responding to the same signals (market or retail prices) in a synchronised way, eroding diversity) is growing among EDBs. Presenting a sea change for consumption patterns and levels of consumer demand, and how EDB networks will be operated and planned in the future. Communication between aggregators and their host network operators will be critical to managing this transition."*

Similarly, Northpower, the EDB for the Whangārei and Kaipara region, responded individually, reiterating the response from the wider industry body:[14]

> *"In principle, we are supportive of increased participation in the wholesale market for small-scale generation, load, and aggregators. However, we have concerns where with greater number of aggregators participating in the wholesale market, there is a lack of communication and visibility of their dispatched resources and locations on EDBs' networks…We suggest establishing appropriate communications between aggregators and EDBs to ensure sufficient information is received by both parties in relation to where new sources are participating within the dispatch notification process, the location on our network…and the aggregator that controls that resource."*

From SolarZero's perspective:

> *"This project provides a window to the future. One where resources behind the meter provide services to the entire power system…we have full visibility of our systems in near real time…"*

This pilot is the start to a potential market where DER contributes to balancing the national grid and to ensure that it can do that both effectively and safely, without leading to operational issues and/or hazards, EDBs need to gain visibility of DER and how it is responding to market/systems signals to appropriately understand and mitigate any network risks.

The implementation of operating envelopes would assist both DER providers and the system operator to understand and help mitigate network constraints. Similarly, DER providers could produce GXP level analyses to map their resources, in order to provide the visibility required by both EDBs and Transpower.

Pilot Outcome Summary

This pilot aimed to demonstrate that up to 30 MW of DER can be aggregated and dispatched into the electricity market and, if required, could be used as a winter peaking mitigation tool to provide additional generation capacity, which is not currently incentivised to participate in market, in a short order of time.

The demonstration was successful, with SolarZero being dispatched by the system operator on four separate occasions (in line with the pilot deliverables), proving that DER has the potential be used to help address winter peak challenges in New Zealand. However, the pilot also identified a number of learnings which will need to considered if DER is integrated as part of a winter peak solution going forward.

The complexities of putting a VPP into practise

Aggregating 10,000 battery systems located across the country to all respond at the same time and be consistently controlled is particularly challenging, and in some cases is outside the control of the VPP owner due to the need to comply with the Electricity Industry Participation Code, grid voltage regulations, voltage constraints, and customer enquiries .

Engage the regulator early and often

Without working directly with the Electricity Authority, it is unlikely this pilot would have been demonstrated in 2023. Their continued active involvement in demonstration projects of this nature will be crucial as DER becomes are larger part of the electricity market equation.

Are current systems appropriate for DER demand response?

In order to stay permissive to the Electricity Industry Participation Code, SolarZero utilised the newly designed, demand-side dispatch system, Dispatch Notified Load (DNL). Although workable, this led to some challenges, as DNL was not designed to allow aggregation across resources located at multiple GXPs to be bid at a single GXP (per island). There are other dispatch options which exist that SolarZero could have used, though these would have required a Code exemption.

System operator and electricity distribution businesses' visibility constraints

Although bidding at a single GXP per island suited SolarZero (with a power distribution of 24 MW at the North Island GXP and 6 MW at the South Island GXP), Transpower found aggregation to this level challenging to accurately model in New Zealand's nodally-based power system. They have since suggested, in response to an Electricity Authority consultation, that any DER with greater than 1 MW at a single GXP should be dispatched via that GXP rather than being aggregated and any DER less than 1 MW can aggregate, at a regionally appropriate GXP, up to a maximum of 5 MW. Also, via a consultation response, a number of electricity distribution businesses noted their concerns regarding the lack of regional visibility of DER and the potential impact DER 'herding' may have on the local network.

Looking forward to winter 2024 and beyond

What has been demonstrated with the pilot is that DER can be made available, via a VPP, as generation capacity of last resort, in a forecast low residual market situation. The pilot demonstrated the potential value for both an insurance policy, to have the generation available, and a delivery mechanism to bring it to market. The following sections pose important questions to be considered to further progress the initiative for winter 2024 and beyond.

Is there value in a winter peaking product?

During the pilot, a number of articles were published surrounding the winter peak issue within New Zealand, with one highlighting that of the ten largest peaks of all time on New Zealand's electricity grid, nine have occurred since 2021 and half were in winter 2023 (see Figure 7).[15, 16, 17]

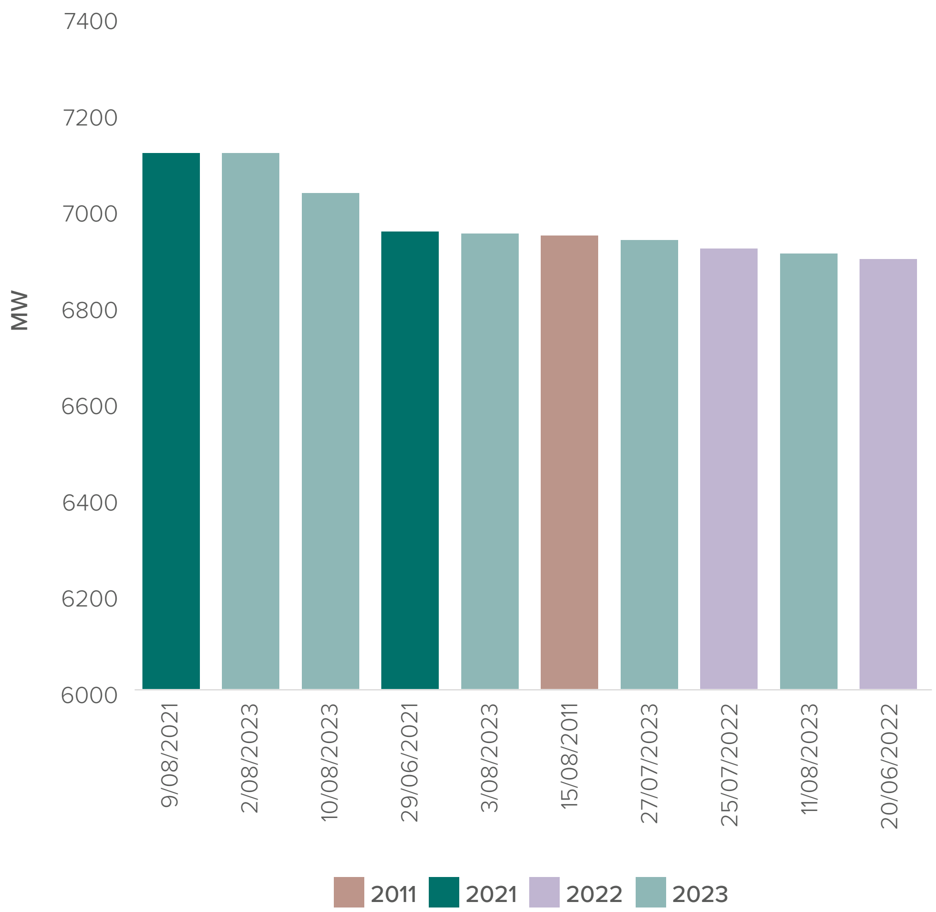
Electrification is expected to become the most common demand-side approach to decarbonisation, so it is likely that these peaks will continue grow for at least the next few years, until smart demand-side innovations and consumer behaviour change result in a flattening of demand driven capacity peaks

In order to meet our climate targets, decarbonisation will need to occur through electrification. This will place more importance on the resilience on the grid's power supply, against a backdrop of increasing intermittent renewables and decommissioning of fossil fuel base load and peaking plants.

At present, the security of supply standards, as defined in Part 7 of the Code, specify a North Island winter capacity margin (WCM) of 630-780 MW. Upon conducting a cost-benefit analysis, the EA deem that the costs associated with building additional peaking generation begin to outweigh the benefits of preventing an expected energy or reserve shortfall at 22 hours per annum – i.e. 22 hours of involuntary load shedding or reserve scarcity per year.[18]

Considering this, all pilot participants agree that there is value in DER winter peaking flexibility as the energy which can be provided by DER has the potential to close this cost-benefit gap.

Figure 7: The 10 largest load peaks of all time on New Zealand's electricity grid.



If there is value, what are the incentives to participate?

Despite all agreeing upon the pilot's value, there has been lengthy discussion between the pilot participants on what are the incentives to participate?

All participants agreed that there was clear value in the insurance of having the capacity available for dispatch in forecast low residual events, however complexity is introduced when considering the incentive mechanism for the availability and dispatch of this capacity and through what formal market mechanisms incentives could be made.

The two options considered were:

1 commercial arrangements with retailers to help manage their peak exposure to spot price; or

2 an ancillary service.

In the case of commercial arrangements, independent electricity retailers (who do not have a generation arm) are more exposed to the spot price and it would potentially be attractive to them, in the event of a winter peaking problem, to hedge against scarcity prices ($10,000/MWh) by negotiating with a demand-side participant to purchase additional generation (or load curtailment) at a lower price.

An example in regard to this pilot is that the majority of SolarZero's customers are registered with the retailer, Ecotricity, upon signing up to a SolarZero agreement. If a winter peak event were to occur and SolarZero were dispatched via DNL, Ecotricity would require less electricity at scarcity prices due to SolarZero's batteries reducing their customers' consumption of grid electricity at peak times.

When considering the above, a commercial arrangement is more likely valuable to non-vertically integrated retailers. However, at present, there are limited market opportunities for commercial arrangements between a load aggregator and other parts of the electricity sector.

In regard to an ancillary service (a service procured by the system operator to support the reliable operation of the power system and assist them to meet their obligations under the Code), the creation and design (along with the incentive structure) sits with the Electricity Authority.

Other peaking ancillaries have been deployed internationally, including the Reliability and Emergency Reserve Trader (RERT) and Wholesale Demand Response Mechanism (WDRM) by the Australian Energy Market Operator (AEMO), and the ERCOT Contingency Reserve Service (ECRS) in Texas, USA.[19 20] All these mechanisms focus on ensuring system reliability during periods when the supply demand balance is tight or to prevent grid emergencies.

The above examples have resulted in high electricity prices and, in some cases, market manipulation. In 2022/23, the RERT was activated twice in Queensland at grid scarcity (market price cap of $15,500 AUD/MWh), delivering a total of 41 MWh across the year for an average price of $50,334.52 AUD/MWh based upon pre-activation (availability), activation, and intervention costs.[21, 22] In ERCOT, the ECRS, on June 20th 2023, led to generators withholding energy from the market until scarcity levels as they were both incentivised to be available for dispatch (in the event of scarcity) and were paid significantly more for their electricity than they would have been if they were operating as they would typically.[23]

Although these examples show peaking ancillaries do exist elsewhere, there is potential for significant issues, and large costs to consumers, if designed incorrectly. The system operator has long been calling for additional investment in flexible power system resources (such as DER, fast-starting generators, batteries and demand response), as there were at least four low residual situations in winter 2023 which would likely have become grid emergencies if additional generation did not offer into market.

From this pilot, we have determined that there is value in having additional generation, outside of the market, available for dispatch during a low residual event to act as effectively an insurance policy to prevent a grid emergency.

If this additional generation becomes part of a commercial arrangement between other market participants, the resource would likely already be accounted for under normal market operations and the certainty of the insurance value is eroded as it is not able to be dispatched by the system operator due to the capacity already being in market in the event of a low residual. This then points to an ancillary service, however, it is likely that the need for the service may only be temporary.

Ara Ake, Transpower and the EA consider that in five to ten years, peak may not continue to present the issues we currently face due to increased DER, unlocking visibility and other technology solutions (as well as future scenario planning across both distribution and transmission to reduce unnecessary overbuild). However, removing this service could be challenging as there will be market participants who have developed business cases dependent upon its existence and the system operator will likely include the service in its security of supply assessment.

SolarZero expects that the natural tendency will be for peak to continue to increase beyond this timeframe as households continue to electrify. It is their view, that without active management of peak well into the future, including effective policies and incentives, the power system will become inefficient and very expensive unless a clear choice is made between ongoing peak management products (at all levels of the power system) versus the more traditional approach of building centralised distribution and centralised infrastructure.

Although this pilot has brought a range of issues to attention, it is clear that there is no obvious way to bring this product to market which is free of challenges going forward. If this product is considered valuable as a winter peaking ancillary service for the New Zealand electricity market, despite the challenges identified above, there are valuable learnings to be had from other jurisdictions.[xiv, 24]

xiv The Market Development Advisory Group (MDAG), in their *Price discovery in a renewables-based electricity system: Final Recommendations Paper* to the EA, have recommended the development of new flexibility products (similar to Australia's 'Super Peak Swap' product, which targets the higher demand hours in the morning and evening), as well as enhancing price discovery by requiring market-making for flexibility products.

What needs to change to incentivise other DER aggregators to provide winter peak services?

There are concerns from load aggregators that the proposed code changes to support winter peaks do not go far enough to solve the imminent problem.

Octopus Energy, an international power company and owner of the largest VPP in the UK, in response to the EA consultation paper state that:[25, 26]

> *“the requirement of a minimum of 1 MW dispatchable load per submission GXP…is a significant barrier for use with domestic controllable assets, (but) allowing traders to aggregate the load to a single GXP (or at least a smaller number), this will allow smaller traders to begin participating in dispatch notifications much earlier.”*

However, they also note:

> *“…we feel the proposed changes don’t go far enough to encourage uptake of dispatch notifications in the short term…Being able to participate in dispatch is at the moment a considerable undertaking. The required effort to integrate with both WITS and the system operator, as well as provide additional reporting to the Authority are significant.*
>
> *We feel that the only incentive to participate is in controlling spot market risk…For the smaller trader, with relatively small numbers of controllable assets in the market today, this is likely to only have a small dollar benefit… Octopus would like to see additional incentives to help accelerate participation.”*

Enel X, a global company who work with commercial and industrial energy users to develop demand-side flexibility and offer it into wholesale capacity, energy and ancillary services markets worldwide, also submitted a response to the EA to reflect *“on the broader question of whether the dispatch notification and dispatchable demand frameworks are the most effective mechanism for catalysing greater levels of demand side participation in the electricity market.”*:[27]

> *“In Enel X’s experience operating in many global markets, demand bidding mechanisms have failed to see any meaningful uptake. This is because the benefits rarely outweigh the costs, complexity and risks of participating. While the proposed change regarding aggregation makes sense, it does not address this fundamental issue. As a result, there remains very little incentive to participate, and it’s therefore unclear whether the mechanism will see any meaningful level of participation.”*

When considering these responses, together with the results of the pilot, it indicates further investigation and analysis is required, to compare the benefits and risks of market and ancillary service options.

Is enabling innovation part of the solution?

During the pilot, the system operator identified potential operational risks associated with the aggregation of widespread DER to a nominal GXP, however SolarZero have expressed the risks and challenges associated with moving away from that approach to a nodal, individual GXP level from the perspective of a VPP owner and meeting other system operator requirements.

Upon considering the system operator's proposed aggregation solution going forward, SolarZero expect that only one third of their capacity would be able to be dispatched to market via dispatch notification, whilst the remainder would need to be aggregated with other demand-side participants at each given GXP.

There is a risk that this requirement would exclude some participants and disincentivise others in bringing VPPs and DER solutions into the market to support winter peak. It also risks overlaying a further system cost by requiring input from a third-party aggregator (such as Enel X), where GXP-based load availability does not exceed 1 MW. This could result in a reduction in DER participation, leading to an overall cost implication for consumers, with the counterfactual being increased investment in generation, transmission and distribution infrastructure.

The alternative, as was done in this pilot, is being able to participate as a demand-side load station (or some other alternative) and dispatch their capacity in full via a virtual GXP scenario. Although this is SolarZero's ideal approach, despite their concerns with the system operator's proposed changes, Transpower outlined in their consultation response that their preferred approach is to "require all dispatch notification purchasers to bid at a nodal level irrespective of size", however their secondary recommendation was that any with less 1 MW at a single node (or nodes) would be permitted to aggregate at a nominal, regional GXP up to a total of 5 MW.

The system operator's reasoning for this change is due to the significant cost associated with modelling the inclusion of 1 MW or less of DER in the power system for very little benefit, combined with the loss of accuracy in load forecasting and the potential for transmission constraints. In reality, the latter approach Transpower have proposed, although this is not their preferred option, would likely allow the majority (if not all) of SolarZero's systems to be dispatched via dispatch notification, the change being that aggregation would need to be done across a number of additional GXPs, as opposed to just one per island (as was done for this pilot).

With all of this in mind, before any future decisions are made, it is crucial that both the benefits and risks identified during this pilot of using DER as a potential solution to New Zealand's winter peak problem are fully considered, as well as the trade-offs, one of which is potentially involuntary load shedding during the winter peaks (in the absence of alternate solutions) as the grid becomes more and more reliant on intermittent renewable generation.

Considering rising forecast electricity demand, the changes which are occurring in global power systems and, despite being regularly updated, the latest version of the Code (the version the system operator bases their operation of the system on) having been written 14 years ago (under the assumption of an electricity system based on centralised generation), what we do know is that innovation and non-traditional approaches will need to form part of the solution if we are to ensure electricity is secure and affordable for Aotearoa. In 14 years from today, assuming we have met our climate targets, it is likely there will be a range of DER, flexibility and demand-side solutions forming part of our electricity market. We expect that solar batteries will be regularly dispatched to the market, and the dispatch of electric vehicle batteries will also be commonplace with some nations potentially not requiring centralized generation due to demand-side innovations (see Utrecht Vehicle-2-Grid pilot).[28]

As the clean energy transition continues to accelerate, and DER increases, New Zealand will face many challenges and we need to innovate and learn by doing to meet these challenges.

Unlocking the value of DER for the NZ electricity sector

This pilot has demonstrated that DER is a valuable solution that can be used in the toolbox to address winter peak, however, as SolarZero and other DER aggregators grow, there will likely be a significant volume of untapped potential which could contribute to various other challenges in the electricity system.

The key technical aspects to be considered in unlocking this potential include the need for:

- a market mechanism designed specifically for dispatching aggregated DER. As this pilot has demonstrated, there are currently no market mechanisms which are fully fit-for-purpose to dispatch DER.
- increased visibility of DER at both a system-level (Transpower) and distributor-level (EDBs) to ensure appropriate system modelling can be achieved, the actions of aggregators can be safely accommodated on local networks and to prevent any unintended consequences, including shifting an issue to another part of the electricity sector.

However, a more important question, going beyond the technical aspects, is "Where in the system does DER deliver the most value?"

- For a customer, DER such as the solar and battery systems used in this pilot have the potential to reduce their electricity costs (noting that all costs in the sector ultimately fall to the end customer), increase their resilience to grid/network disruptions, and could provide them incentive opportunities if they allow their systems to be used by an aggregator for dispatch into market to counter network or system constraints.
- For a retailer exposed to the market pricing, DER has the potential to reduce their customers' load, requiring less generation to be purchased to cover their retail book.
- Distributors can utilise DER flexibility to support constraint management and defer capital expenditure on their network.
- For the system operator, if the appropriate mechanisms are in place, DER can be used in instantaneous reserves or, as demonstrated in this pilot, as peaking flexibility.

Determining where the greatest value lies will require industry-wide engagement, but something crucial to teasing out DER's true value and optimal place in the future electricity system is ensuring that that there is a robust regulatory framework for DER participation. Such a framework, alongside innovative commercial arrangements and platforms could unlock the value of DER and provide confidence to the sector, in the reliability of DER to provide a meaningful impact in our electricity future and a potential alternative to the traditional approach of building centralised infrastructure.

Appendix

TRANSPOWER CAN

Customer Advice Notice

To:	CAN NZ Participants	**From:**	The System Operator
Sent:	14-jun-2023 15:12	**Telephone:**	0800 488 500
Ref:	4826846562	**Email:**	NMData@transpower.co.nz

Revision of:

Low Residual Situation

Affected dates and times:

14 June 2023 17:30 - 18:30
15 June 2023 07:30 - 08:30

The System Operator advises that **National** residual generation is less than 200 MW for the above times.

For affected times, participants are requested to:
- Ensure energy, wind generation, reserve offers, and load bids are accurate.
- Increase energy and reserve offers.
- Submit difference bids for discretionary demand (for the identified time plus 1 hour either side).
- Increase transmission offers where generation may be constrained.

Process and further requests, if situation worsens:
This CAN gives you early notice that if the situation worsens we may have insufficient generation to meet demand and cover reserves for a contingent event. If insufficient generation and reserve offers appear in the schedules, we will send:

- A Warning notice (WRN) which will make further requests to participants to help resolve the situation. This could happen up to gate closure (7 days to 1 hour ahead of real-time).
- A Grid Emergency Notice (GEN) within one hour of real-time which will make further requests to grid-connected consumers and distributors to take action to alleviate the situation.

For more information, or if you are aware of information that could impact system security, please advise the Security Coordinator on 0800 488 500.

For further information on procedures for low residuals or subsequent insufficient energy and reserves see this link https://www.transpower.co.nz/system-operator/operational-information

Up to date island residual information is available on the WITS website

Media enquiries, call 021 195 8613 (please do not text)

...

References

1 CEO Forum. (2022). CEO Forum submission to the Electricity Authority in response to the Driving efficient solutions to promote consumer interests through winter 2023 consultation paper.

2 Electricity Authority. (2023). Options chosen to better manage peak electricity demand this winter.

3 Electricity Authority. (2023). Managing peak winter electricity demand: Driving efficient solutions to promote consumer interests through winter 2023.

4 Energy Efficiency and Conservation Authority. (2020). Ripple Control of Hot Water in New Zealand.

5 Ministry of Business, Innovation and Employment. (2021). Investigation into electricity supply interruptions of 9 August 2021.

6 Transpower. Demand side participation.

7 Transpower. (2023). Interim Requirements for Connection of New Generation Technology

8 Transpower. (2023). GL-EA-1052 Guideline for Connection DD & DNL into the Electricity Market

9 Transpower. Notices for insufficient generation: Timeline, overview of notices and sample notices.

10 Electricity Authority. (2023). Dispatch notification enhancement and clarifications: Consultation paper.

11 Electricity Authority. (2017). Real-time pricing proposal: Consultation paper.

12 Transpower. (2023). Response to the EA consultation: *Dispatch notification enhancement and clarifications.*

13 Electricity Networks Aotearoa. (2023). Response to the EA consultation: *Dispatch notification enhancement and clarifications.*

14 Northpower. (2023). Response to the EA consultation: *Dispatch notification enhancement and clarifications.*

15 Energy News. (2023). More thermal, batteries, demand response for winter peaks.

16 BusinessDesk. (2023). Escaping electricity blackouts in 2024 will need investment now: Transpower.

17 Energy News. (2023). Low residuals forecast until mid-month.

18 Electricity Authority. (2012). Security Standards Assumptions Document.

19 AEMO. Wholesale demand response mechanism

20 AEMO. Reliability and Emergency Reserve Trader (RERT)

21 AEMC. (2022). 2022-23 market price cap now available

22 AEMO. (2023). Reliability and Emergency Reserve Trader (RERT) End of Financial Year 2022-23 Report

23 Forbes. (2023). ERCOT Update: Texans' Electricity Bills Are Going Up—And It May Not Be Legal

24 Market Development Advisory Group. (2023). Price discovery in a renewables-based electricity system: Final Recommendations Paper

25 Octopus Energy. (2023). Octopus Energy grows UK's largest virtual power plant

26 Octopus Energy. (2023). Response to the EA consultation: *Dispatch notification enhancement and clarifications.*

27 Enel X. (2023). Response to the EA consultation: *Dispatch notification enhancement and clarifications.*

28 IEEE. (2022). THIS DUTCH CITY IS ROAD-TESTING VEHICLE-TO-GRID TECH: Utrecht leads the world in using EVs for grid storage

Ara Ake

Future Energy Development

Address: 8 Young Street, New Plymouth 4310
Email: info@araake.co.nz
araake.co.nz