Smart Meter Capability Trial

February 2021

Phase 1 Evaluation Report

Important notice

PURPOSE

AEMO publishes the Smart Meter Backstop Mechanism Capability Trial – Trial Evaluation Report under section 51 of the National Electricity Law (NEL).

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VERSION CONTROL

Version	Release date	Changes
1	15/7/2021	Initial report
2	16/7/2021	Minor amendment to Executive summary

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Executive summary

This report provides a technical overview of smart meter capabilities that could provide consumer benefits and be utilised in managing power system security.

Background

The continued rapid uptake of distributed photovoltaics (DPV – household solar) and other Distributed Energy Resources (DER) is creating opportunities to innovate in ways that support consumers and the power system. The potential exists for DPV owners to engage in new markets by harnessing new capabilities that are required for system security purposes, maximising the value of their investment for themselves and all energy users.

The first stage in this approach is to demonstrate any capability functions as required. Late last year, the South Australian Energy Minister formally requested and funded AEMO to trial capability latent in Advanced Metering Infrastructure (AMI) or 'smart meters' in South Australia, seeking to improve energy security and market benefits for South Australians by testing a new way to maintain security of a power system with high levels of DPV penetration.

The trial also provides the opportunity to enhance aggregate visibility of DER at a point in time; aggregate visibility is essential to understanding when the power system is at risk, what measures need to be taken to mitigate these risks, and whether they have been successful, and also provides consumers with better information to manage their bills.

There are two key risks emerging in the transition to a distributed power system, both of which relate to the ability to keep the power system in balance, or to keep the flow of power 'stable' (technically known as in a 'secure operating state', which AEMO has specific responsibilities in the National Electricity Rules to maintain).

The new power system operating challenges in maintaining security of a distributed power system are:

1. A minimum amount of system load is required to keep traditional power plants operating and providing balancing services the power system currently cannot operate without. The majority of DPV is not currently interoperable[1] and as installation rates continue, load levels are declining in every jurisdiction across the National Electricity Market (NEM). In circumstances where jurisdictions are operating in an island or under constrained interconnector conditions[2], the minimum level of system load required to keep large-scale traditional plants (synchronous generators) on-line is being approached. Breaching these thresholds can result in the tripping of these generators and a system blackout.
2. AEMO must 'keep' a level of generation in reserve, as a back-up to manage situations such as a large power plant unexpectedly disconnecting, or a transmission line failing leading to the same result. The reserves are quickly called upon to fill the energy shortfall and avoid the system collapsing. During such power system events DPV is also disconnecting, and as DPV continues to be installed the NEM is approaching levels that could soon exceed the amount of generation held as a back-up[3]. New inverter capabilities are expected to mitigate this risk by preventing DPV from disconnecting, but given no power system anywhere in the world has been operated with the DPV penetration rates seen in Australia, it is prudent to consider other risk mitigation measures.

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[1] Interoperable refers to the ability to respond to remote communications and signals.

[2] Island conditions refers to periods where South Australia is disconnected from the rest of NEM, potentially due to outages or incidents at the interconnector.

[3] See Appendix 5 in AEMO's 2020 *Electricity Statement of Opportunities* , at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2.

South Australian smart meters have capability to manage these challenges by disconnecting the DPV either directly or at consumers' premises, which increases the load available to keep synchronous generators on-line or maintains the level of DPV in the system such that the level of back-up generation kept in reserve would not be exceeded.

Such operational measures would only be taken in rare circumstances where the alternative is expected to place power system security at risk **and all other operational and market measures have been exhausted.**

In September 2020, the installation of DPV with the ability to be remotely disconnected and reconnected ('curtailed') became mandatory in South Australia, and testing the technical implementation pathways is an important measure to ensure the capability operates as required in an emergency.

On 14 March 2021, during a period of low system load and planned network outages, 10 megawatts (MW) of DPV was curtailed via these new mandatory requirements, contributing to the secure operation of the South Australian network[4]. As a scale comparison, large generators can exceed 600 MW; most residential consumers have systems around 5 kilowatts (kW)[5] in size in their homes. This trial was conducted prior to this event.

Design and scope of the trial

This trial tested the *technical capabilities* of meters, which are the focus of this report. The market reforms required for consumers to engage in two-sided markets are being developed under the Energy Security Board's (ESB's) Post 2025 program[6]. This program, at the request of energy Ministers, is undertaking a future market design process to ensure the power system is able to continue the integration of renewable energy and DER within a framework that is fit-for-purpose when it comes to these new technologies and fully benefiting from the capabilities they can deliver. This includes realising the potential to utilise flexible behind-the-meter supply and demand options that consumers could choose to harness and engage in a two-sided market to create value. AEMO strongly supports the development of new markets which could harness the capability under trial in this report or mitigate its use for emergency purposes, along with transparent and clear communication and market signalling in regards to any application.

Before the 14 March 2021 event, the first phase of this trial established and tested the activation protocols between network operators to enact DPV curtailment and the robustness of communication capabilities of the meters to deliver the actual response. This was trialled by the communication of test instructions from AEMO to Network Service Providers (NSPs) to Metering Coordinators, who then **simulated** remote capability to disconnect and reconnect the trial meters. The trial was designed such that no consumers were or could be impacted by the simulation; this was achieved by using proxies to simulate the response on a live system, which meant there could be no impact to the consumer.

The trial used 25,232 smart meters, representing 13% of all smart meters in South Australia, with 48.5 MW of additional load identified as coming into the system. Data provided indicates 50% of trial meters could respond correctly to a signal within 60 seconds, with the remainder responding in under 13 minutes. This response time is well within that required in an emergency situation to prevent cascading failure.

With such capability proven and already in place, this demonstration paves the way for market development, allowing consumers to benefit from their smart meters while enabling a cost-effective approach for managing power system security. New products can be considered around the voluntary provision or availability of 'load' to avoid involuntary shedding, or even to offer voluntary and paid DPV curtailment as a hedge against negative pool prices. These products could minimise the need for emergency backstop mechanisms, while providing value to all energy users.

This report will focus on the outcomes of the end-to-end implementation of the test protocol from AEMO, NSPs, and Metering Coordinators, conducted earlier this year. Metering Coordinators voluntarily participated in this trial to showcase existing unused capability in South Australia and the benefits and effectiveness of its application. It is important to note these results demonstrate the effectiveness of smart meter disconnection

[4] For more information, see https://aemo.com.au/newsroom/media-release/solar-pv-curtailment-initiative-by-sa-government-supports-the-nem.

[5] 1,000 kW = 1 MW.

[6] See https://esb-post2025-market-design.aemc.gov.au/.

when applied in isolation, as occurred under the trial. In practice, control room measures to manage minimum system load may involve an interplay between a suite of capabilities, such as SA Power Networks' Enhanced Voltage Management system, each of which will influence the response of the other.

Aggregate visibility of DER at the time of minimum system load is essential to maximising the effectiveness of the combined measures used to maintain power system security. Without this, the application of measures is largely uncoordinated and lacks the ability to accurately reconstitute the near-real time forecast to determine if the system is expected to remain in a secure operating state.

This proxy test simulated the response of DPV to communications on a live system, providing detailed understanding of the end-to-end implementation of the capability especially the performance of communication and robustness of response.

Summary of key learnings from the trial

- Existing processes and smart meters can provide the speed and robustness of communications and capability required to act as an emergency operating tool. The trial used existing manual implementation methods; automation would significantly increase the speed and robustness of response.
- Smart meter capability could be harnessed to provide consumers new markets and services.
- Aggregate visibility of DER devices can be achieved via communications through smart meters. This visibility included a detailed measured level of response which would enable system operators to more accurately forecast if the system was expected to remain in a secure state.
- The fastest performing Metering Coordinator performed the simulation successfully to 91% of their trial fleet within 60 seconds.

Next steps

Phase 2 of the trial will look into the capability for commercial sites to be curtailed using similar mechanisms, by testing voluntary physical disconnection of DPV through communications protocols.

The ESB's Post 2025 program is currently undertaking a market design process including how to activate 'two-sided markets'.

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1. Trial Phase 1 overview

1.1 Background

As the number of DPV installed at households (or "behind the meter") continue to increase, the power system is increasingly sourcing generation from these DPV resulting in a more distributed power system. There are two key risks emerging in the transition from a centralised to a distributed power system, both of which relate to the ability to keep the power system in balance, or to keep the flow of power 'stable' (technically known as in a 'secure operating state', which AEMO has specific responsibilities in the National Electricity Rules to maintain).

The new power system operating challenges in maintaining security of a distributed power system are:

1. A minimum amount of system load is required to keep traditional power plants operating and providing balancing services the power system currently cannot operate without. The majority of DPV is not currently interoperable[7] and as installation rates continue, load levels are declining in every jurisdiction across the National Electricity Market (NEM). In circumstances where jurisdictions are operating in an island or under constrained interconnector conditions[8], the minimum level of system load required to keep large-scale traditional plants (synchronous generators) on-line is being approached. Breaching these thresholds can result in the tripping of these generators and a system blackout.
2. AEMO must 'keep' a level of generation in reserve, as a back-up to manage situations such as a large power plant unexpectedly disconnecting, or a transmission line failing leading to the same result. The reserves are quickly called upon to fill the energy shortfall and avoid the system collapsing. During such power system events DPV is also disconnecting, and as DPV continues to be installed the NEM is approaching levels that could soon exceed the amount of generation held as a back-up[9]. New inverter capabilities are expected to mitigate this risk by preventing DPV from disconnecting, but given no power system anywhere in the world has been operated with the DPV penetration rates seen in Australia, it is prudent to consider other risk mitigation measures.

1.2 Trial objectives

Minimum system load and the unintended disconnection of distributed photovoltaics (DPV – household solar) during system disturbances are emerging as imminent risks to power system security in South Australia and are emerging as risks quickly in other jurisdictions. This Smart Meter Capability trial ('trial') sought to test new operational capability as another tool to contribute to the management of these risks (which are detailed above) and to demonstrate the functionality for market and consumer benefits.

Phase 1 targeted the development and testing of metering capability and protocols to enable the emergency shedding of consumers with DPV, to support power system security. All tests were simulated and there was zero impact on consumers, a key objective of the trial.

The aim was to gain an understanding of the end-to-end communication performance, robustness of response, and demonstration of smart meter capability as a power system operating tool that could also be used by consumers to engage in new markets. Table 1 displays a breakdown of the objectives and results for the Phase 1 trial.

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[7] Interoperable refers to the ability to respond to remote communications and signals.

[8] Island conditions refers to periods where South Australia is disconnected from the rest of NEM, potentially due to outages or incidents at the interconnector.

[9] See Appendix 5 in AEMO's 2020 *Electricity Statement of Opportunities* , at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2.

Table 1 Summary of objectives of trial

Objective	Was this achieved?	Commentary
Establish the protocols required to remotely shed and restore selected consumer sites (AEMO – Transmission Network Service Provider [TNSP] – Distribution Network Service Provider [DNSP] – Metering Coordinator)	Yes	• Protocols were developed over a number of joint workshops with all participants of the trial. • Phone calls were used as the mode of communication between all parties (AEMO – TNSP, TNSP – DNSP, DNSP – Metering Coordinators). • Emails were used for traceability of the trial. • Scripting was developed and agreed.
Provide market participants and interested stakeholders with visibility of this capability being tested	Yes	• Draft Market Notices were delivered via email to registered market participants who requested information on when this testing was conducted (see example Appendix A1).
Provide greater understanding of the capabilities and time of response from Metering Coordinators to consumers' smart meters	Yes	• Proxy provided feedback that the response has been actioned. • Speed of response data was provided after the test (some Metering Coordinators could provide this feedback with response of action).
Demonstrate the benefits of this capability to consumers and the market	Yes	• The trial indicates that targeted curtailment via the meter could reduce the number of consumers disconnected; approximately a quarter of the number of consumers may be impacted, compared to traditional 'feeder' level shedding. • Success of the capability demonstrates opportunities for the development of voluntary load markets and hedging opportunities where generation and flexible load are isolated at the meter for individual response.

1.2.1 Trial description

Phase 1 of the trial focused on collaboration with trial participants to jointly develop documented protocols and review existing metering capabilities to support the implementation of operational arrangements for DPV curtailment. The protocols and capabilities would provide an avenue for the system operator to give direction to Network Service Providers (NSPs), and NSPs to Metering Coordinators, to remotely shed and restore selected residential consumer sites with minimal real-time impact to consumers. Note that Phase 1 of the trial did not include commercial sites, due to alternative metering arrangements in place at such sites.

The trial was undertaken to understand any shortcomings of the proposed protocols and capabilities in supporting power system security during rare emergency conditions.

This was a 'proxy' trial to establish the communication channel from AEMO – Transmission Network Service Provider (TNSP) – Distribution Network Service Provider (DNSP) – Metering Coordinators, and the protocols to simulate premise shedding via smart meters. Scripted phone calls were used between the participants, with the Metering Coordinators sending a proxy signal to the meter to test the disconnect and reconnect functionality. This proxy signal was selected to ensure the trial did not impact consumers.

The trial did not involve:

- Physical disconnection and reconnection of consumer sites, because capability was demonstrated through a simulated response on live systems only (no sites or DPV were shed/restored through the trial).
- Any commercial arrangements between the parties with respect to accessing the smart meter capabilities (there were no payments made by any party under the trial).
- Any regulatory framework changes (this trial was a Proof of Concept conducted within the existing regulatory environment).

1.3 Trial participants

Participation by all Phase 1 trial participants was voluntary. Table 2 lists the participants and their roles.

Table 2 Trial participants and roles

Name	Role
AEMO	• Developing and coordinating the trial. Chair and secretariat services for the running of workshops; documenting and communicating the protocol.
TNSP – ElectraNet	• Participate and collaborate in the development of the operational protocols in workshops. • Follow and execute the developed protocol and provide AEMO with datasets following each test.
DNSP – SA Power Networks (SAPN)	• Participate and collaborate in the development of the operational protocols in workshops. • Follow and execute the developed protocol and provide ElectraNet with datasets following each test.
Metering Coordinators – • Intellihub • PlusES • Metropolis • Spotless • Vector	• Participate and collaborate in the development of the operational protocols in workshops. • Execute the developed protocol and provide AEMO with datasets following the test.
Metering Data Provider – Secure Metering	• Secure Metering was the Metering Data Provider for Spotless.

1.4 Consumer engagement, stakeholder engagement, and benefits

Phase 1 of the trial consisted of engagement with the voluntary participants including AEMO (trial lead), ElectraNet, SA Power Networks (SAPN), and Metering Coordinators. AEMO also ran a series of briefing sessions for interested stakeholders, such as electricity retailers and consumer groups, to raise awareness of the trial and outline the objectives. It was identified that consumer and other stakeholders would not be impacted by the trial, so no direct engagement was required during this phase.

As a result of the workshops, the trial was able to provide valuable insights into the potential benefits and value of utilising existing installed smart meters. The extent to which the trial outcomes contributed to better understanding or realising this potential is outlined in Table 3.

Table 3 Potential benefit and value of trial outcomes

Potential benefit/value	Impact/commentary
DER visibility improvements	• The remotely read smart meters (type 4 meters under National Electricity Rules [NER] chapter 7) provided a statistically valid sample of the population. These meters provided load profiles at 5- and/or 30-minute intervals. There were some differences with the use of instantaneous read event data, as it was averaged over the interval (see Figure 9). • It is believed that 5-minute data feeds of aggregate actual DPV (gross) generation in aggregate is critical when this tool is used in-conjunction with other tools, and this will be explored in future trial phases.

Potential benefit/value	Impact/commentary
Managed DPV generation of this nature could present a viable option as a DER market	• The capability functioned successfully and within timeframes required for market and operational responses.
Reduction in the number of consumers which might be impacted during interventions for power system security	• This phase of the trial highlighted an efficient way for networks to manage load to support power system security objectives during emergencies – using a targeted rather than blanket shedding approach.
Approach could be effective for other jurisdictions	• It is concluded that the protocols and capabilities would work in other jurisdictions. However further consideration in Victoria would be required to understand any differences in the implementation and capabilities of Victorian Advanced Metering Infrastructure (AMI) smart meters compared to Power of Choice meters in the rest of the NEM (as used in this trial).
Understanding of the requirements and mechanisms required for the current capabilities to participate in Reliability and Emergency Reserve Trader (RERT), Lack of Reserve (LOR) or for market purposes	• Communication and response were key outcomes of this trial. Current systems and processes were found to be suitable within the trial. However, if business as usual (BAU) arrangements were to be established the systems and processes may need further development to enable automated capability and more fit for purpose measurement & verification models.

The outcomes of this trial provide an opportunity to broaden industry understanding of the latent capabilities in smart meters that have potential to support power system security and unlock additional value for consumers.

AEMO considers that the broader implementation of mechanisms and markets delivering power system security services will require broad engagement and understanding of impacts and benefits to consumers and industry.

2. Protocol evaluation

2.1 Trial protocol map

Figure 1 shows a high-level interaction and process diagram for the operational protocol used in the trial. It was agreed that all communications in the trial were to be conducted via phone calls, with follow up emails for traceability.

The protocol begins with AEMO providing an instruction to initiate the proxy to simulate the response. This instruction translates to a direction from both ElectraNet and SAPN, which is ultimately provided to the Metering Coordinators. Metering Coordinators then initiate the proxy to test the communication to their metering fleet participating in the trial. This chain of communication reflects existing roles and responsibilities in network and broader power system operation.

Each of the processes indicated by arrows starting from AEMO's instruction in the figure was assessed, and the results are summarised in Table 4.

Figure 1 Focus of trial to test protocol for simulated response from smart meters highlighting the protocol steps

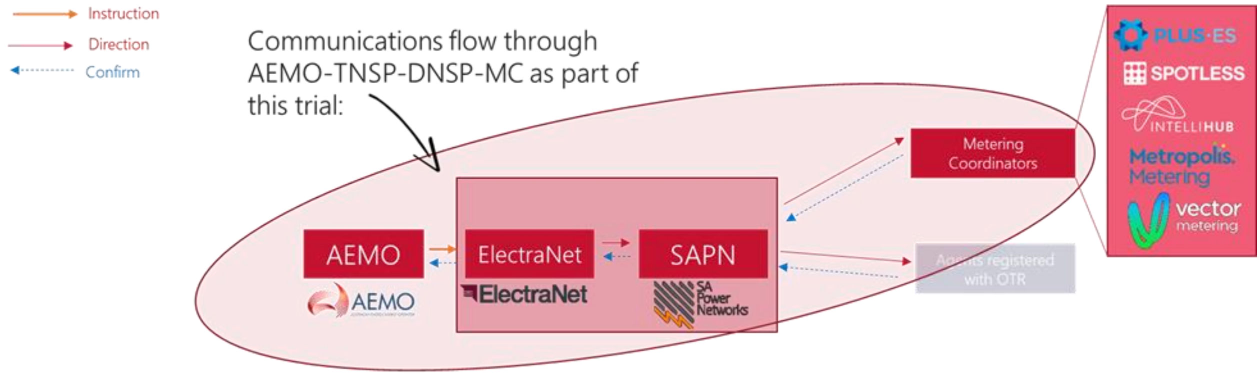


Table 4 Operational protocol process assessment

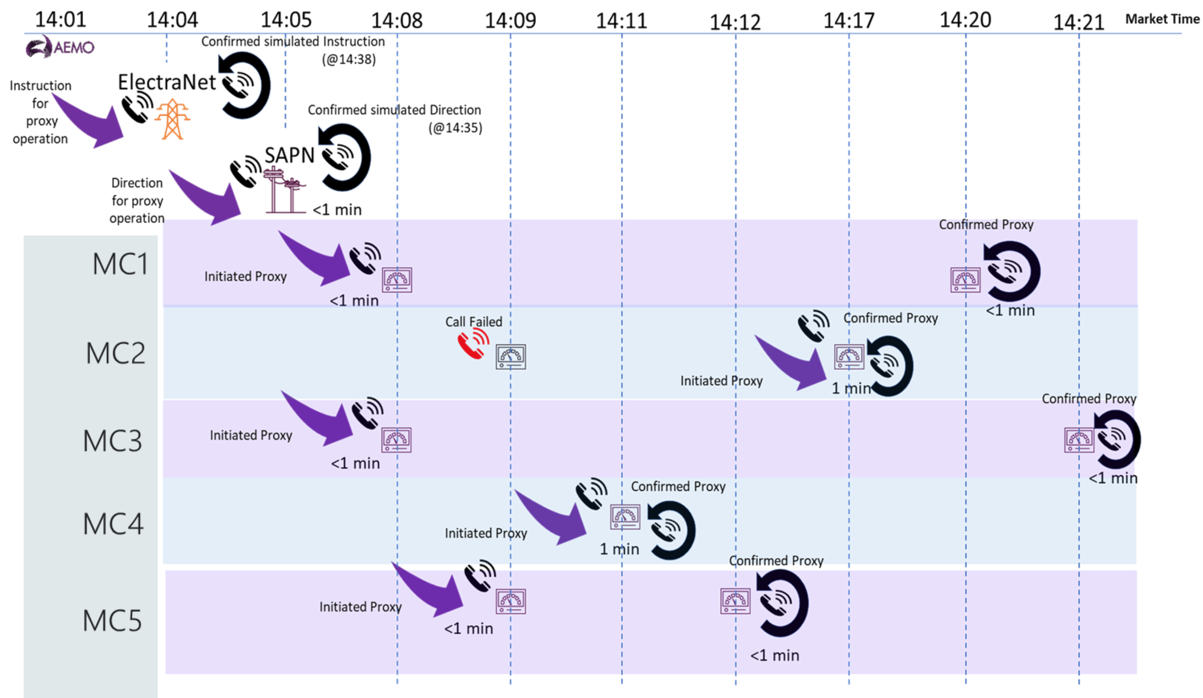
Step	Process	Was this successful?	Commentary
1	AEMO Control Room phones ElectraNet Control Room.	Yes	AEMO used control room staff outside of the control room as proxy of AEMO Control Room – ElectraNet agreed to this arrangement and confirmed numbers prior to test.
2.a	ElectraNet Control Room receives instruction from AEMO to activate simulated proxy for the shedding of whole customer sites with DPV.	Yes	Approved scripts were developed and agreed by AEMO and ElectraNet during coordination workshop.
2.b	Email of Market Participant Notice.	Yes	Appendix A1.1 (for Market Participant Notice).
3	ElectraNet Control Room phones SA Power Networks Control Room.	Yes	Control Room to Control Room communications authenticated the caller and receiver.
4	SAPN Control Room receives direction from ElectraNet to activate simulated proxy for the shedding of whole customer sites with DPV.	Yes	Approved scripts were developed and agreed for use between ElectraNet and SAPN during coordination workshop.
5	SAPN Test Coordinators phone Metering Coordinators.	Yes	All five Metering Coordinators' phone calls were able to be completed in a timely manner – however it did highlight that some SAPN phones were unable to contact international numbers.
6.a	Metering Coordinators receive direction from SAPN to activate simulated proxy for the shedding of whole customer sites with DPV.	Yes	Approved scripts were developed and agreed between SAPN and all five Metering Coordinators during coordination workshop.
6.b	Email of direction from SAPN to activate simulated proxy for the shedding of whole customer sites with DPV.	Yes	Appendix A1.2 (for Email for traceability).
7	Metering Coordinators activated simulated proxy for the shedding of whole customer sites with DPV.	Yes	100% of Metering Coordinators activated the response.

Step	Process	Was this successful?	Commentary
8.a	Metering Coordinators reported back by phone SAPN that direction has been followed.	Yes	Multiple Metering Coordinators (80%) provided a response that was achieved rapidly, while one Metering Coordinator (20%) response was relatively slower. Metering Coordinators (80%) times were very consistent at 10–15 minutes.
8.b	Email from Metering Coordinators to SAPN that direction has been followed.	Yes	Appendix A1.2 (for Email for traceability).
9	SAPN reported back by phone ElectraNet that direction has been followed.	Yes	
10	ElectraNet reported back by phone AEMO that instruction has been followed.	Yes	

Logs of the interactions were kept by all participants during the trial. Each interaction of the protocol was mapped for both the activation of the proxy and the restoration (cancellation of the proxy); see Figure 2 and Figure 3 respectively.

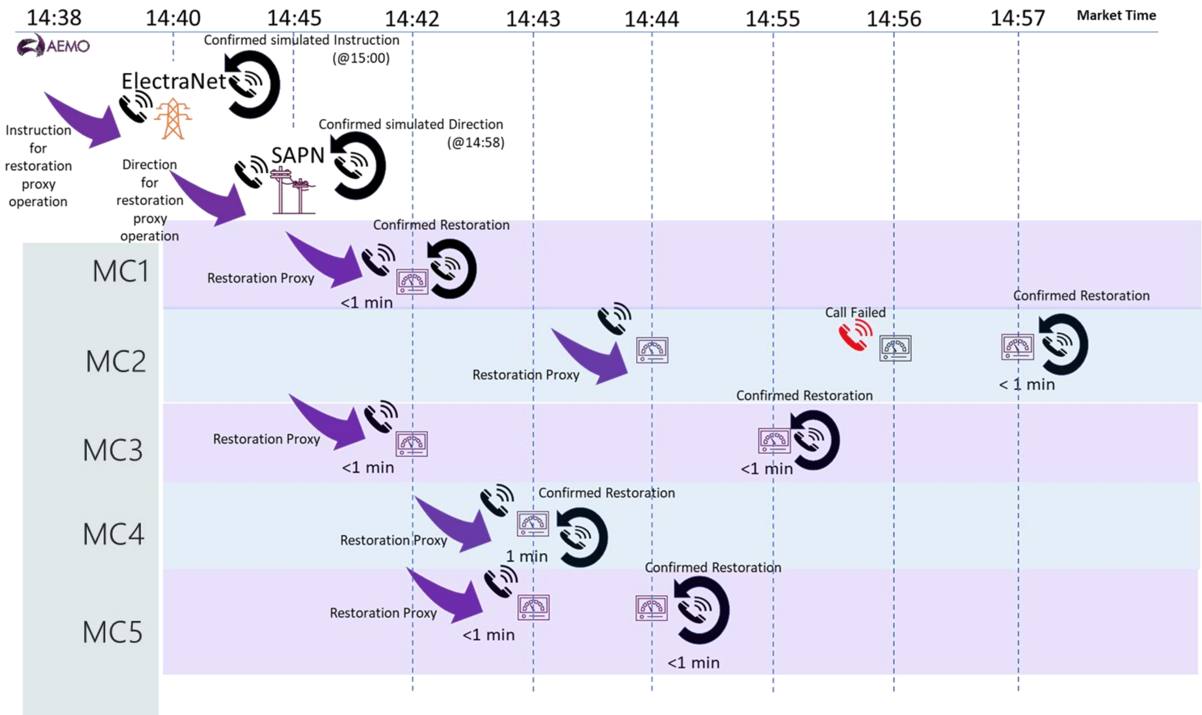
The overall time for AEMO to receive the confirmation of the simulated instructions from ElectraNet was on average less than 30 minutes. This timing meets AEMO's requirements to manage the return of the system to a secure state and for the capability to be used as a market for consumer benefits.

Figure 2 Timing of the chain of command for proxy operation



* Call failed due to SAPN's inability to phone international numbers on some SAPN phones. Metering Coordinator's Control room is located in New Zealand.

Figure 3 Timing of the chain of command for proxy cancel operation



* Call failed due to SAPN's inability to phone international numbers on some SAPN phones. Metering Coordinator's Control room is located in New Zealand.

3. Advanced Metering Infrastructure evaluation

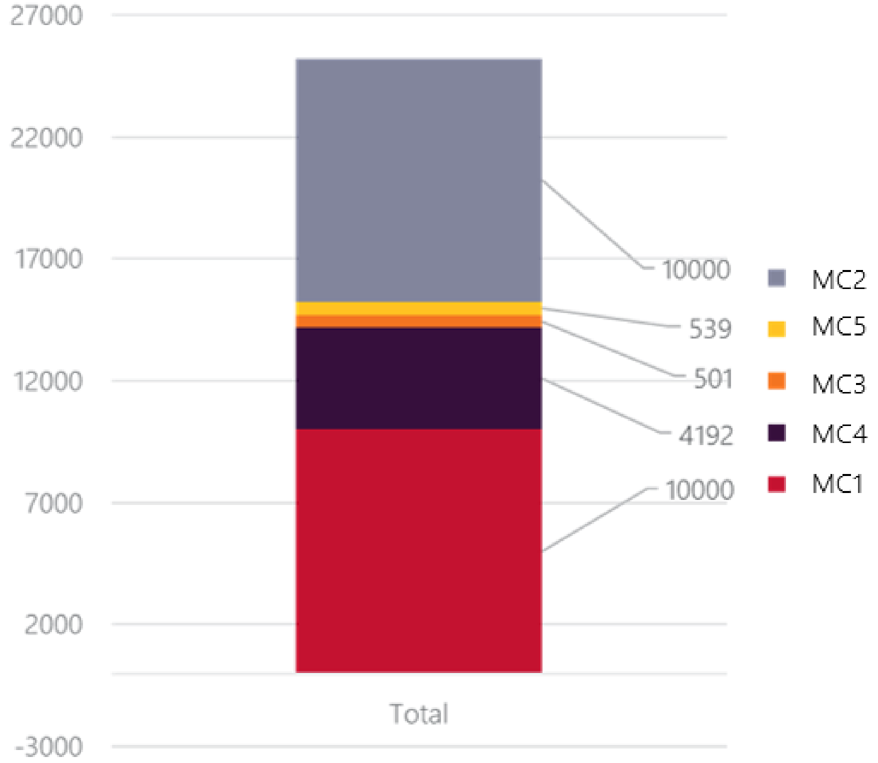
The following attributes formed part of the assessment for developing trial metrics for metering communication evaluation:

- Number of meters within trial.
- Speed and robustness of communication.
- Simulation type and the megawatts delivered.

3.1 Number of meters within trial

Each Metering Coordinator had preselected a sample set from its metering fleet installed in South Australia. These smart meters were all remotely read type 4 meters as defined in chapter 7 of the National Electricity Rules (NER). A total of 25,232 smart meters were part of Phase 1 of this trial; Figure 4 shows the number of meters from each Metering Coordinator.

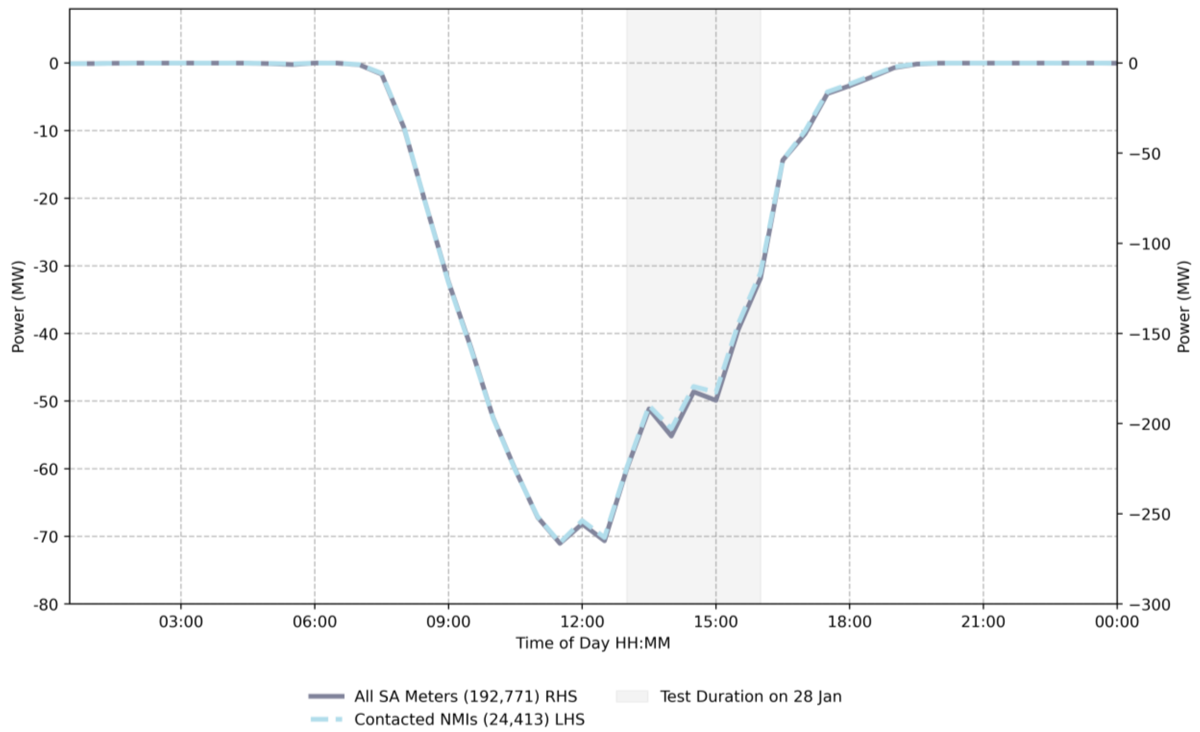
Figure 4 Number of meters for each Metering Coordinator as sample fleet for trial



Note: For the purpose of results, Metering Coordinators have been de-identified as MC1 - MC5.

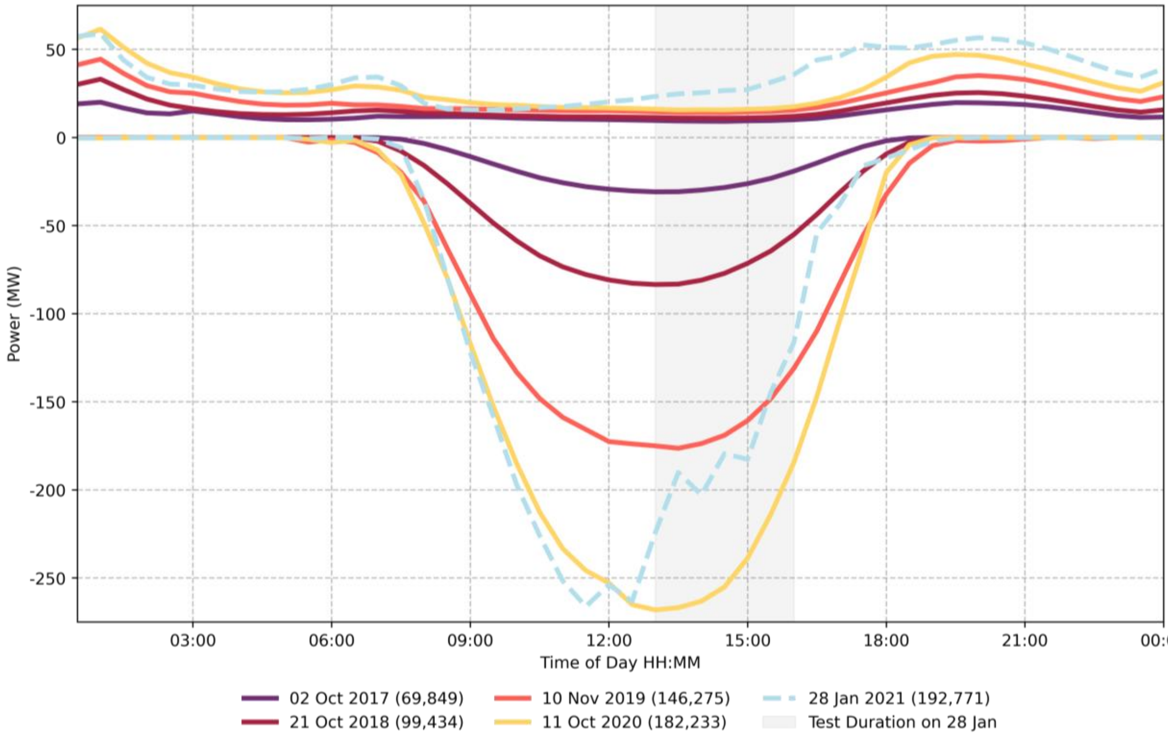
From each of the trial selected meters, a load profile was then produced from market-supplied data. This sample fleet of meters represented 13% of all installed South Australian smart meters, and Figure 5 confirms that it is a statistically representative sample, meaning the trial represents a response rate which is reflective of that which would occur if the capability were available fleet wide.

Figure 5 Net generating National Metering Identifiers (NMIs) comparison: all small residential South Australian NMIs and NMIs contacted during trial



The test was conducted on Thursday 28 January 2021 at 14:00 market time (14:30 Australian Central Daylight Time [ACDT]). The solar output for this day was compared to historical yearly minimum demand days (see Figure 6).

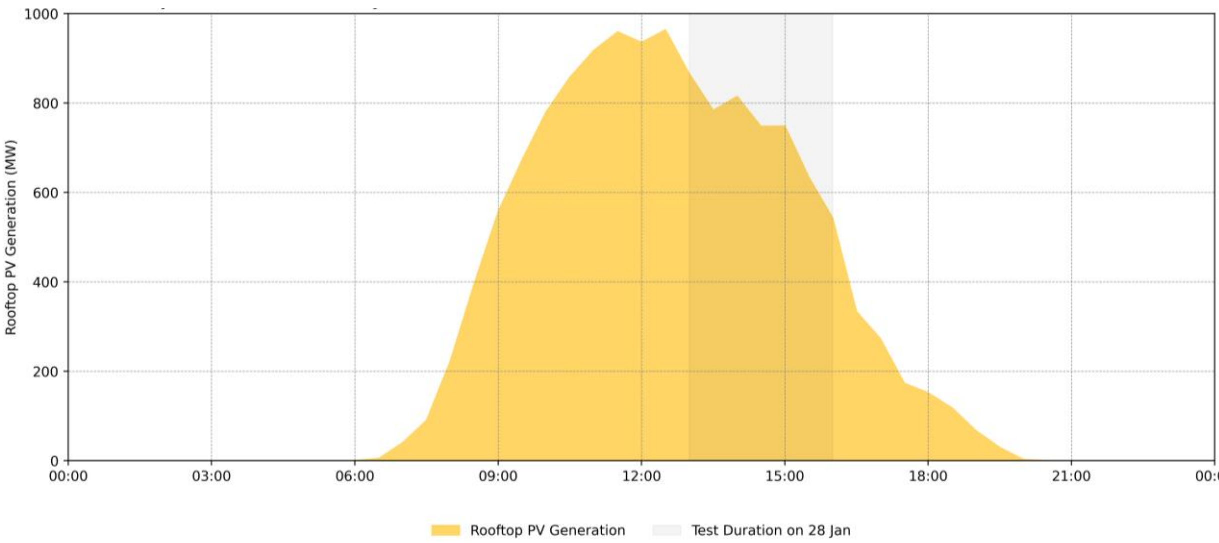
Figure 6 Aggregated net import and export power at South Australia sites with DPV



The two curves for each day are aggregated separated net generation and net load customer sites.

Solar export from consumers with DPV was on track to exceed the previously recorded minimum system load day (11 October 2020), however some high cloud rolled through South Australia at approximately 13:00 ACDT which decreased DPV production by around 50 megawatts (MW). This solar production reduction was confirmed and proved to be consistent by reviewing the overall South Australian DPV generation profile (see Figure 7). The level of response received from the proxy curtailment command is outlined in Section 3.3.

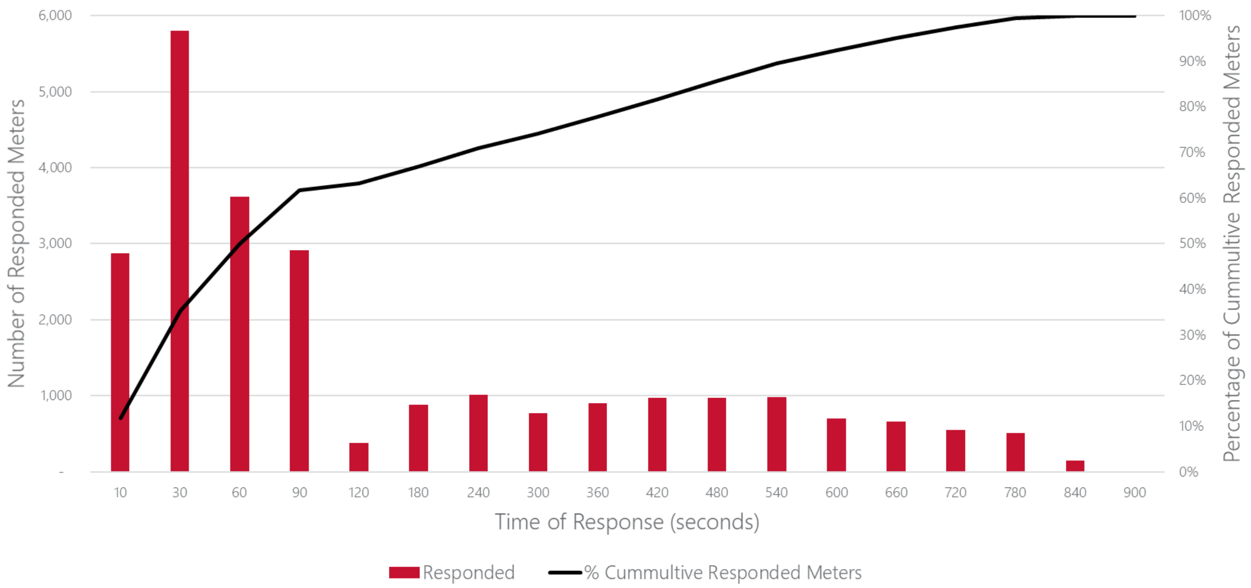
Figure 7 South Australia DPV generation, 28 January 2021



3.2 Speed and robustness of communication

It was agreed with participants that Metering Coordinators would provide AEMO with a dataset following the trial that would detail the time it took for each trial meter to successfully respond to these proxies. These datasets were analysed and are summarised in Figure 8. Analysis of the data shows that Metering Coordinators could successfully communicate and interpret the proxy of 50% of the aggregated fleet of trial meters within 60 seconds. The fastest performing Metering Coordinator performed the proxy successfully to 91% of its trial fleet within 60 seconds.

Figure 8 Successful communication speed of response for trial meters



Overall performance of each Metering Coordinator's simulated communication response using the proxy for both disconnection and reconnection is detailed in Table 5. As smart meters need to successfully communicate with the Metering Coordinators a minimum of once every 24 hours, it can take a few attempts to get a successful communication channel. This small percentage of errors in the setup of a communication channel is not material for this use of the capabilities, as a 98% success rate is more than acceptable robustness for an emergency or market response.

Table 5 Actual simulated communication response using proxy disconnection and reconnection (no physical disconnection occurred)

Metering Coordinator	Missed disconnection proxy	Received disconnection proxy	Successful disconnection proxy %	Missed reconnection proxy	Received reconnection proxy	Successful reconnection proxy %
MC3	43	458	91	11	447	98
MC4	103	4,089	98	30	4,044	99
MC5	35	504	94	0	504	100
MC1	232	9,768	98	85	9,591	99
MC2	209	9,791	98			
Total	**622**	**24,610**	**98**	**126**	**14,586**	**99**

Most Metering Coordinators chose to directly simulate a reconnection of the disconnected meters with the use of reconnection proxy. The success rate of this additional communication was on average 99% successful (range of 98%-100%). Reconnection of meters can be achieved by numerous methods, which can be direct or automatic. Automatic options include failsafe count-down timers or at a specific time (for example, after sunset).

All Metering Coordinators indicated that the sample of meters were selected at random (that is, without discounting meters which were experiencing known communication issues). Had the Metering Coordinators vetted the metering fleet with communication issues, the overall successful percentage would have been increased, and an increase in the sample of meters would also reduce the percentage of meters having communication issues.

Some Metering Coordinators developed tools and processes that provided a "live feed" of the success rate of the command in addition to the real-time operation of the net load/generation balance at the premise. Thus, these Metering Coordinators could understand with a large degree of confidence the amount of response received, and report on this during the call from the NSP. In turn, this means these Metering Coordinators could increase or decrease the number of premises managed as required, in real time. Such a level of fine tuning would provide important system security benefits as certainty of the response is understood, and consumer benefits by being able to effect as few consumers as possible. In addition, these tools provided these Metering Coordinators with improved optionality to further target sites as per a criterion (for example, net exports above a threshold).

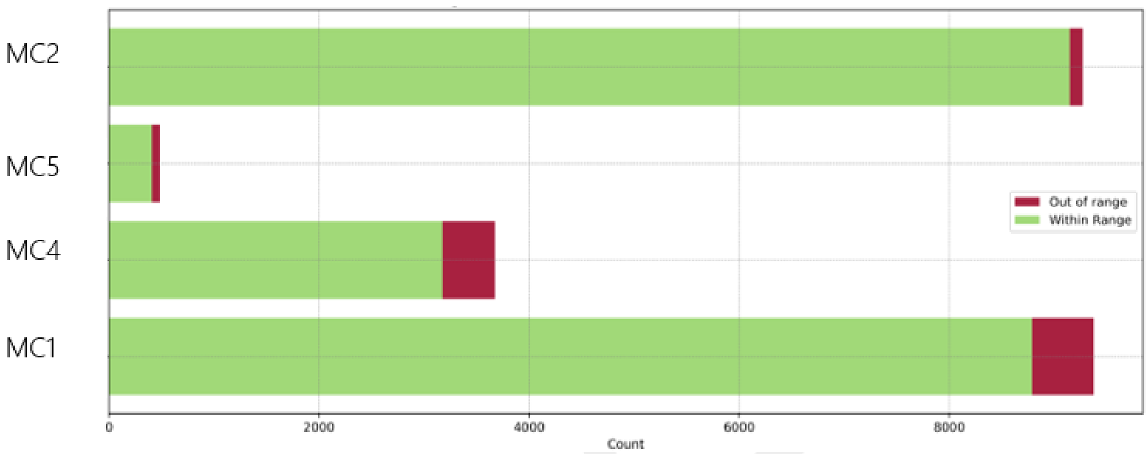
3.3 Simulation method and the megawatts delivered

There were different proxies used by Metering Coordinators to simulate the disconnection and reconnection of smart meters in the trial. Most of the Metering Coordinators used an instantaneous read from each meter. These instantaneous reads returned the instantaneous power (P-Net). The P-Net was provided among other engineering parameters such as reactive power, current, power factor. This method provided a real-time snapshot of the current power flow of each site (that is, net exporting or importing).

The other method used by Metering Coordinators was to conduct an On Demand Read (ODR) on their trial metering fleet. The ODR returns the information between the last read up to the latest completed interval.

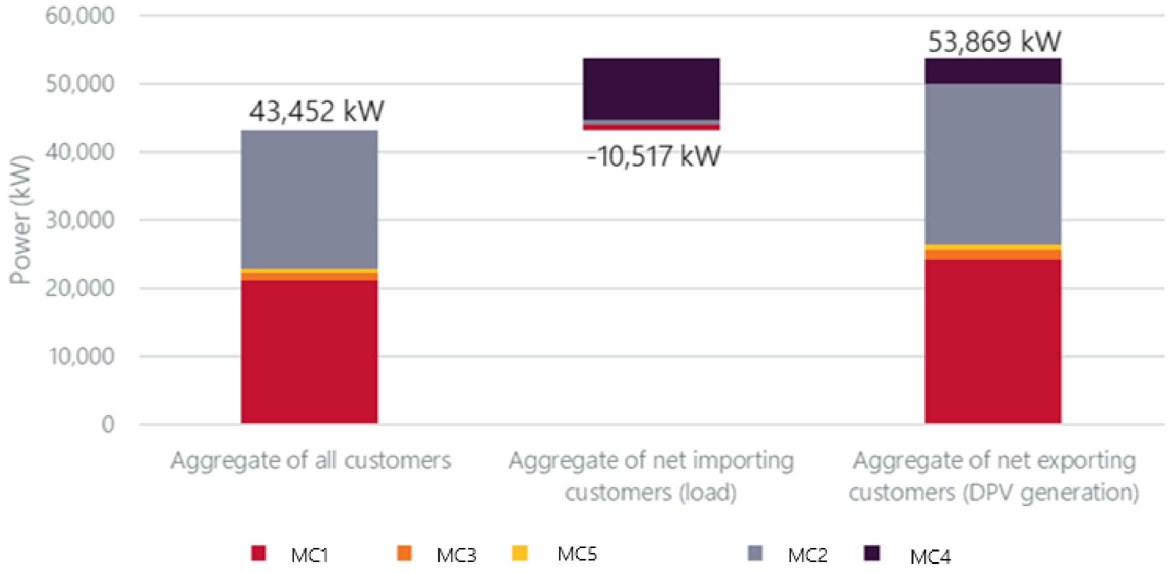
Using validated market data and the datasets provided by each Metering Coordinator, it was possible to correlate the ODR and instantaneous power within a tolerance range of 10%, as shown in Figure 9. The solutions employed by the Metering Coordinators in the trial revealed a high level of speed and robustness in communicating with their metering fleet. Improvements in the situational awareness and real-time visibility in aggregate is anticipated to be explored in a future phase of this trial.

Figure 9 Count of NMIs where P-Net falls within range of metered data (10% tolerance)



It was calculated that a total of 43.452 MW of generation would have been disconnected if a real disconnection was used rather than the opted proxies. Figure 10 highlights that some consumers were not exporting consumers (that is, they were a load). The trial did not discriminate between net exporting or net generating consumers. If it had – as would likely be the case if using this capability in an emergency event – then net load consumers would have remained connected, resulting in an additional 10.517 MW of load remaining connected, bringing the total potential of 53.869 MW of generation being disconnected.

Figure 10 Aggregation of response from trial test NMIs



One of the alternatives to managing minimum system load is to shed net exporting feeders. The outcome achieved under this trial is equivalent to 97,000 consumers being shed by such 'traditional means' (for example, 97 x 11 kilovolt [kV] feeders with each 11 kV feeder exporting 500 kW); that means, a quarter of consumers would be impacted if this method was used.

4. Overview of key learnings

Phase 1 of the trial has demonstrated that the speed and robustness of the communications from Metering Coordinators is within the operational requirements for market purposes, or to deliver a response to support power system security. It is noted that this trial was delivered with existing systems and processes, and if it was to move to a business as usual (BAU) activity some additional development and cost may be required, however this would also improve the speed and robustness of some solutions. A regulatory review would need to be conducted for any broader roll-out.

The interaction of this tool with others used by the networks to maintain power system security needs to be coordinated. Some capabilities such as Enhanced Voltage Management (EVM), developed by SAPN to cause DPV to disconnect, may take in the order of 10 minutes to stabilise. The time to stabilise would need to be taken into account before smart meters are used to disconnect. This is required as some DPV will have disconnected via the EVM tool and thus a premise may have already changed from a net exporting (that is, a generator) to a net load. This could be managed with a selection or qualification of each meter before the operation is actioned.

Considerations to the above will be tested in Phase 2 of this trial to better understand the value of increased visibility of the DPV by the separation of load and generation via smart meters. This separation will also allow greater precision for DPV management and market options. It is thought that separation will help assist visibility, the ability to forecast, and management of DPV. Table 6 summarises the key learnings.

Table 6 Key learnings of Phase 1 of the trial

Area	Key learnings
Operational	• Speed and robustness of response suitable for power system market and operational practices • Targeted curtailment via smart meters could significantly reduce the overall number of consumers impacted when such emergency intervention is required, compared to feeder shedding.
Capability	• Speed and robustness of response suitable for power system operational and market practices. • Targeted curtailment via smart meters could significantly reduce the overall number of consumers impacted when such emergency intervention is required, compared to feeder shedding.
Regulatory	• Provisions in the rules is one of the key regulatory issue that needed to be addressed for this trial, and which will be relevant in a broader roll-out of DPV curtailment in the NEM. • These trial outcomes may be relevant to the Australian Energy Market Commission's (AEMC's) Review of the Regulatory Framework for Metering Services (see https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services).
Communications	• In a broader sense this highlights the importance of individually testing any phone links which are not already established, especially where complexities exist (international numbers, call forwarding, automated calls etc.) • Need to carefully consider the provided and expected feedback through the chain of command (i.e. Metering Coordinator to SAPN, SAPN to ElectraNet). As the number of providers increases, there is a risk that some providers will be slower in their response which will delay the feedback.
Markets	Current systems and processes were found to be suitable within the trial. However, if market arrangements were to be established the systems and processes may need further development to enable automated capabilities and more fit-for-purpose measurement and verification models.

5. Next steps

The outcomes of this trial highlights key focus areas for further investigation:

- Creating the potential for similar protocols to be used to gain aggregate visibility over DER to provide consumers with better data and support systems, and network operators for the purpose of balancing supply and demand in a high DER power system.
- Phase 2 of the trial will look into the capability for commercial sites to be curtailed using similar mechanisms, by testing physical disconnection of DPV through communications from AEMO to DNSPs to Metering Coordinators. Outcomes from this phase will provide insights into how and if commercial sites can offset potential impact to the broader community, and what incentives may potentially be utilised for commercial sites to provide these services in market frameworks ahead of any application of an emergency last resort backstop.
- The Energy Security Board's (ESB's) Post 2025 program is currently undertaking a market design process including how to activate 'two-sided markets'.

A1. Appendix

A1.1 Draft Market Notices

A1.1.1 Market Notice – Shedding of DPV

As part of the trial being conducted today in South Australia – this is a trial email to simulate a market notice to participants.

This is a trial only and no customers will be shed during this time as part of the trial.

Notice Type:	DPV Shed Trial
Notice Type Description	NEL 51 Trial Direction
External Reference:	DPV Trial Shedding Direction- ElectraNet
Reason	AEMO ELECTRICITY MARKET NOTICE – **Simulation/TRIAL ONLY** **Distributed PV Shedding Direction** in the SA Region AEMO has directed DPV shedding commencing at 14:00 hrs 28/01/2021 in the South Australia region This notice is a direction under section 51 of the NEL. AEMO is trialling the simulation of Distributed PV shedding at selected customers sites with PV. Manager NEM Real Time Operations
Participant	AGL

A1.1.2 Market Notice – Restoration of DPV

As part of the trial being conducted today in South Australia – this is a trial email to simulate a market notice cancelation to participants.

This is a trial only and no customers will be shed during this time as part of the trial.

Notice Type:	DPV Restore Trial
Notice Type Description	NEL 51 Trial Direction
External Reference:	DPV Restoration Direction - AGL
Reason	AEMO ELECTRICITY MARKET NOTICE – Simulation/TRIAL ONLY Cancellation - DPV Restoration Direction in the SA Region – [28/01/2021] Refer to AEMO Electricity Market Notice [DPV Shedding Direction- AGL] Direction to restore all shed DPV issued at 14:00 hrs 28/01/2021 AEMO has directed DPV restoration commencing at 14:30 hrs 28/01/2021 in the South Australia region This notice is a direction under section 51 of the NEL. AEMO is trialling the simulation of Distributed PV shedding at selected customers sites with PV. Manager NEM Real Time Operations
Participant	AGL

A1.2 Email of Direction

A1.2.1 Email of Direction from SAPN Activate Simulated Proxy for the Shedding of Whole Customer Sites with DPV

SAPN– Simulation/TRIAL ONLY

Distributed PV Shedding Direction

This notice is a direction under section 51 of the NEL. AEMO is trialling the simulation of Distributed PV shedding at selected customers sites with PV. This test is to simulate both the market notice and direction to as a trigger for Metering Coordinators via the SAPN to activate simulated proxy for the shedding of whole customer sites with DPV.

AEMO directs **ElectraNet** to shed DPV as follows:

- commencing at [2:00 pm on Thursday 28th Jan 2021] to commence shedding whole customer sites with DPV as soon as possible.

ElectraNet has directed SAPN under the trial to simulate the shedding of Distribution PV commencing at **[2:00pm Thursday 28th January 2021]** and to commence DPV shedding as soon as possible.

Please confirm with SAPN when [**Metering Coordinator**] has complied with this direction.
This is a trial only."

ElectraNet may provide further operational advice for additional DPV shedding beyond this initial requirement.

This direction is issued at 14:00 hrs on **[28/01/2021] – Market Time.**

A1.2.2 Email of Direction from SAPN to Activate Simulated Proxy for the Restoration of Whole Customer Sites with DPV

SAPN– Simulation/TRIAL ONLY

Distributed PV Restoration Direction

This notice is a direction under section 51 of the NEL. AEMO is trialling the simulation of Distributed PV restoration of shed selected customers sites with PV. This test is to simulate both the market notice and direction to as a trigger for Metering Coordinators via the SAPN to activate simulated proxy for the restoration of shed whole customer sites with DPV.

AEMO directs **ElectraNet** to resotre DPV as follows:

- commencing at [2:30 pm on Thursday 28th Jan 2021] to commence restoring whole customer sites with DPV as soon as possible.

ElectraNet has directed SAPN under the trial to simulate the restoration of Distribution PV commencing at **[2:30pm Thursday 28th January 2021]** and to commence DPV restoration as soon as possible.

Please confirm with SAPN when [**Metering Coordinator**] has complied with this direction.
This is a trial only."

This direction is issued at 14:30 hrs on **[28/01/2021] – Market Time.**