United Energy Demand Response – Final Project Performance Report

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1. Summary

This document is the Final Project Performance Report of the United Energy Demand Response Project for the ARENA Advancing Renewables Programme – Demand Response programme (RB006). It fulfils an obligation under the Knowledge Sharing Plan to provide an update on the status of the delivery of the Dynamic Voltage Management System rollout project including sharing of results and lessons learnt.

United Energy has delivered the demand response services through the use of remote-controlled voltage reduction at 47 zone substations initiated from its Network Control Centre. This service uses the existing fleet of smart meters deployed across the distribution network to provide time-lagged customer voltage data from all connected smart meters to enable reductions in voltage while maintaining voltage compliance during the demand response event. To do this, the voltage across the network can be reduced by 3% on average to deliver at least 30MW of demand response within 10 minutes when called upon, sustained over a 4-hour period between 10am and 10pm on business days.

Due to the mathematical relationship between voltage and real power, as demand increases, the level of demand response provided by United Energy will also automatically increase. Previous use of this method of demand response always had some level of risk in that it could not be guaranteed that customer voltages did not fall below the stipulated regulated limits during the voltage reduction period, and this elevated the risk of customer claims from appliance damage. This risk has now been addressed with United Energy completion of an advanced technique using smart meters to implement demand response using voltage reduction, without deteriorating our regulatory voltage compliance. This technique uses actual time-lagged voltage information (by 25-60 minutes) from the entire fleet of smart meters (AMI) to provide the feedback loop to inform and set boundaries on the voltage reduction control system.

This report documents the summary of the previous milestone reports and also the test results of the 8th AEMO demand response test conducted in May 2020. This test confirmed United Energy's demand response reserve capability for the last period.

Any parties interested in discussing the contents of this report directly with United Energy are encouraged to contact United Energy at planning@ue.com.au.

The previous milestone reports are available on United Energy's website.

2. Project Background

United Energy (UE) utilised ARENA project funding to rollout the Dynamic Voltage Management System (DVMS) capability to its entire network. This system has allowed UE to provide the maximum amount of demand response to AEMO using the voltage reduction technique while keeping customer voltages within safe limits.

Prior to the rollout, DVMS had been trialled on UE's Clarinda (CDA) zone substation in Clayton. The successful completion of this trial in January 2018, paved the way for this capability to be installed in all of the 47 zone substations.

DVMS works by gathering voltage data provided from customer smart meters on a zone substation and sending it to a Network Analytics Platform (NAP) to make decisions on optimising the voltages according to the dynamic load pattern. The command to select the appropriate customised voltage set-point is then sent to the relevant voltage regulating relay (VRR) at the zone substation. DVMS currently resides within the MOSAIC SCADA system and provides UE with the advanced capability to manage voltage within the network.

DVMS operates by controlling the voltage within the regulatory limits using on-load tap changers at zone substations to manage the customer voltage profiles to $V_{99\%}$ for normal operation and $V_{1\%}$ for demand response operation. A range of different voltage set-points were required to be programmed within the VRRs at each zone substation and as such VRRs needed to be replaced with new transformer management relays (either DR-E3 or REG-D). Moreover, protection settings of high-voltage (HV) customers supplied by each zone substation needed to be taken into consideration when the voltage set-points were determined. Field rectification works (typically distribution transformer tap changes) were also required, following the sequence of the VRR replacement works to maximise the demand response capability.

2.1. DVMS Overview

Figure 1 shows an overview of the end-to-end DVMS.

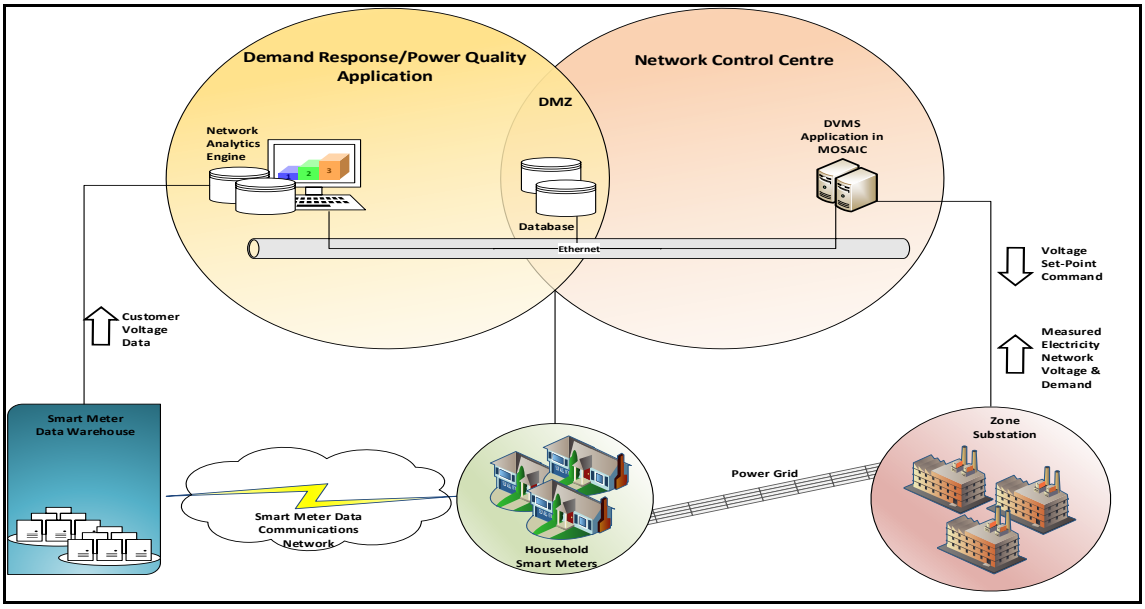


Figure 1 Dynamic Voltage Management System Overview

The existing VRRs in UE's zone substations were not capable of operating with multiple voltage set-points and they needed to be upgraded or replaced with new DR-E3 or REG-D transformer management relays to possess the required capabilities. Therefore, the VRRs at all zone substations were programmed with new 7 pre-set bus voltage float set points; namely *DV*0 to *DV*6. These settings were programmed with pre-defined setting values in the field VRRs as listed in Table 1.

Table 1: Voltage Set-Points for Voltage Regulating Relays Deployed in DVMS

No	OLTC[1] Operation Setting
1	Standard
2	Emergency1
3	Emergency2
4	DV0
5	DV1
6	DV2
7	DV3
8	DV4
9	DV5
10	DV6

The setting changes introduced voltage adjustments on the network. Also, the float voltages in both the Master and Follower relays were adjustable.

It should be noted that there is an ability to disable the DVMS at the host.

To achieve the objectives of the DVMS, two main operating modes[2] were deployed in the NAP: "$V_{99\%}$ = 253V (V_{PQ})" and "$V_{1\%}$ = 216V (V_{DR})" for power quality improvement and demand response purposes, respectively.

As demonstrated in Figure 2, using $V_{99\%}$ has resulted in compliance of the 99%[3] of the customers with the Victorian Electricity Distribution Code (the Code) limit of 253V. This operating mode is in use most of the time during the year.

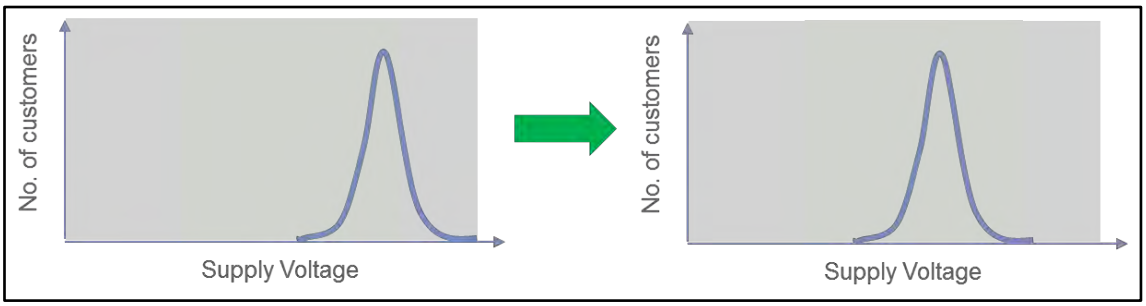


Figure 2 Operating Mode $V_{99\%}$ (V_{PQ}) Deployed by DVMS for Power Quality Improvement

In order to deliver maximum demand reductions when called upon by AEMO without compromising supply quality, the operation will be changed from $V_{99\%}$ to $V_{1\%}$. $V_{1\%}$ can be used to reduce the voltage levels at the selected zone substations by retaining 99%[4] of the customers in compliance with the Code limit of 216V as demonstrated in Figure 3.

[1] OLTC = On-Load Tap Changer.
[2] The third mode is also available to minimise the number of non-compliant customers when these two operating modes cannot result in improvement of quality of supply.
[3] According to AS 61000.3.100-2011.
[4] According to AS 61000.3.100-2011.

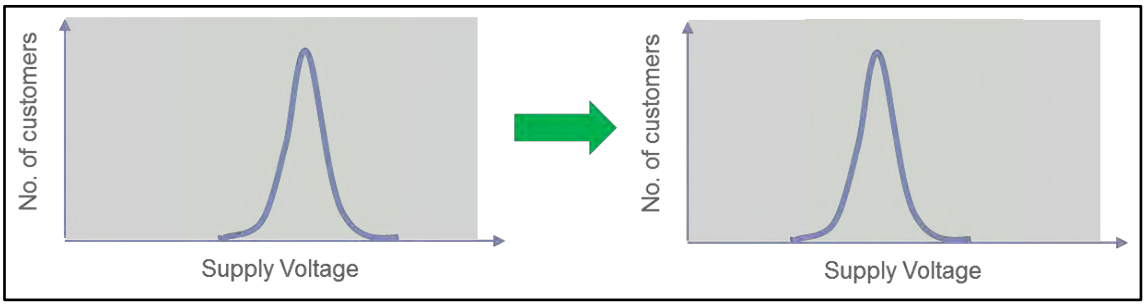


Figure 3 Operating Mode $V_{1\%}$ (V_{DR}) Deployed by DVMS for Demand Response

To increase the level of voltage reduction and consequently demand reduction, UE adjusted the tap settings of distribution transformers to narrow the bell curve demonstrated above and also rectify the under-voltages received by the customers at the left side of the histogram.

2.2. DVMS Context

Figure 4 demonstrates different parts of the DVMS.

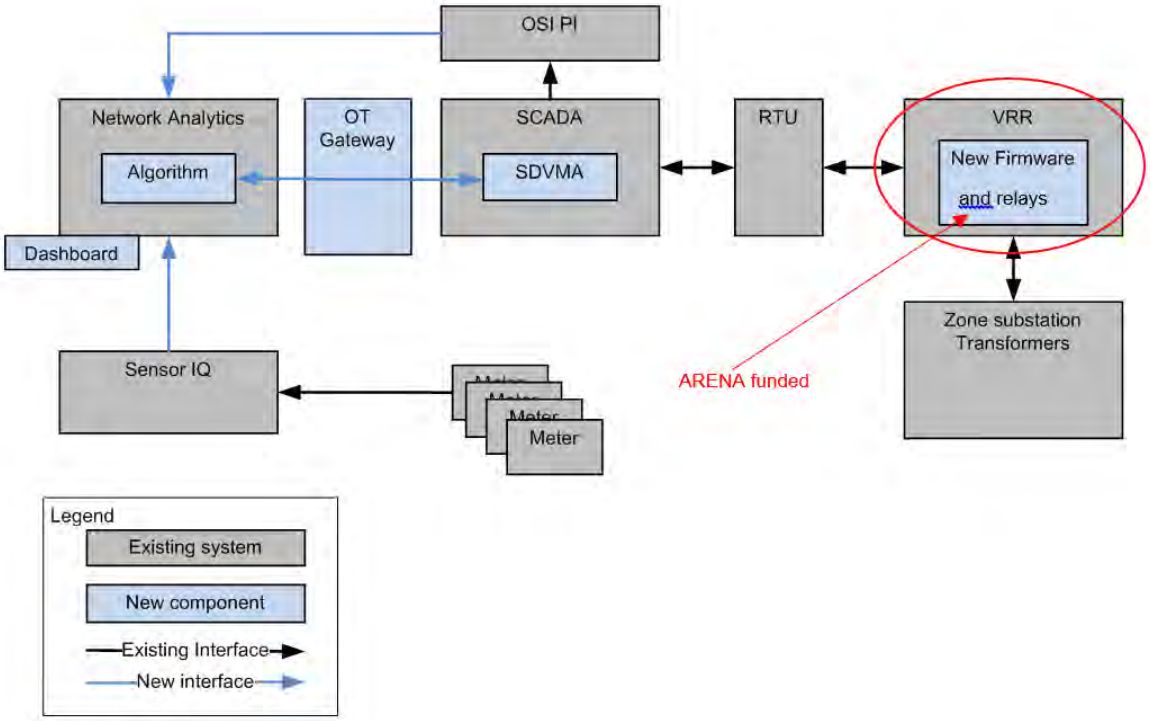


Figure 4 Sub-Systems Required for Implementing Dynamic Voltage Management System

DVMS consists of below sub-systems:

- ***VRRs**:* VRRs needed to be implemented with new firmware to provide new dynamic voltage set-points to support the DVMS scheme.
- ***RTUs:*** Remote terminal units.
- ***SCADA:*** MOSAIC SCADA system.
- ***SDVMA:*** The new SCADA dynamic voltage management application (SDVMA) developed by CGI company that is part of the MOSAIC SCADA system now. SDVMA periodically seeks the voltage recommendations from the OT[5] Gateway and applies the latest recommendation to the field VRRs after validation.

[5] Operational technology.

- ***OT Gateway:*** New infrastructure to enable security compliant integration from Corporate network into the OT network.
- ***Network Analytics Algorithm:*** New algorithm developed in NAP to generate voltage recommendations for zone substation VRRs based on smart meter data via SensorIQ.
- ***Network Analytics Dashboard:*** New dashboard developed in NAP to display smart meter voltages for given zone substation.

3. System Development

3.1. Network Analytics Platform

Table 2 summarises the DVMS-related business requirements extracted from the Network Analytics Business Requirements Specification upon which the design for the algorithm was developed. These business requirements were deployed for the trial with recommendation for improvements for the DVMS rollout.

Table 2: Business Requirements for the Network Analytics Applications for Dynamic Voltage Management System

No	Description
NAP_1	The solution requires the ability to automatically calculate instructions for the dynamic voltage set-point of the zone substation transformer based on smart meter voltage data analytics. The algorithm required is to identify low-voltage (LV) population profiles that can be shifted to minimise putting customers outside of the Code limits. The algorithm is to run at every minute.
NAP_2	The solution requires the ability to automatically monitor the dynamic voltage set-points of the CDA zone substation based on decisions resulting from analytics calculations and should be expandable to other zone substations. The solution requires an interface from NAP to MOSAIC SCADA to support generation of a control message (voltage recommendation) to change the VRR voltage set-point. This interface shall exchange messages at a maximum of 1-minute intervals.
NAP_3	The solution shall provide recommendations using standard SCADA naming conventions for relevant VRR voltage set-points.
NAP_4	The solution requires NAP to be advised via an acknowledgement (Ack) message that the control message was actioned.

The algorithm design deployed in NAP for DVMS is as follows:

1. The analysis of the smart meter data shall be manually switchable between two modes of control:
    a. $V_{1\%} = V_{DR}$ – shall control to a level that ensure no more than 1% of the customers on the zone substation are under 216V;
    b. $V_{99\%} = V_{PQ}$ – shall control to a level that ensure no more than 1% of the customers on the zone substation are over 253V; and
    c. When there are more than 1% of customers experiencing over-voltages and under-under-voltages then, the algorithm shall control to ensure that the maximum number of customers stay compliant (between 216V and 253V).
2. The control to change from a $V_{1\%}$ to $V_{99\%}$ control limit or vice versa shall be done from MOSAIC SCADA and interfaced to the NAP algorithm.
3. The readings that are recording abnormally low or abnormally high values (both configurable) such as sites which are experiencing brown-out, voltage sags due to short circuits or outages shall be removed via a filter:
    a. Smart meter voltage data under 203V shall be ignored from the control algorithm; and
    b. Smart meter voltages data over 277V shall be ignored from the control algorithm.
4. The number of smart meter reads received, as well as their timeliness, are assessed to decide if the data present is a current statistically-valid sample:
    a. Data older than 10 minutes shall not be analysed; and

b. 100% of zone substation population's data shall be analysed to produce the voltage recommendation.

5. The algorithm shall run based on historical data received.
6. A recommendation shall not cause a recommended step change of more than 2 steps (based on running every 5 minutes).
7. A change recommendation shall not be based on a change that was implemented within 2 minutes either side of the data time stamp being analysed to recommend the new change.
8. The recommendation shall have two time stamps:
    a. The time the recommendation was produced; and
    b. The data time stamp the recommendation was based on.
9. A second round of checks shall be performed to limit the changes from pushing customers outside of the Code limits. There are three possible VRR setting change values:
    a. No voltage change is required;
    b. Change voltage set-point to x; and
    c. No confidence/not enough data, no recommendation issued.
10. The algorithm shall filter recommendations such that there is on average only 6 recommendations output to SCADA per day.
11. Once the raw VRR voltage setting change recommendation is calculated, the result shall be written to a database location.
12. NAP shall generate an .xml file from the database record of the recommendation.
13. The algorithm shall not cater for split bus conditions. This shall be performed and disabled on the MOSAIC SCADA side.

Figure 5 demonstrates the algorithm design for NAP which has been deployed by the DVMS.

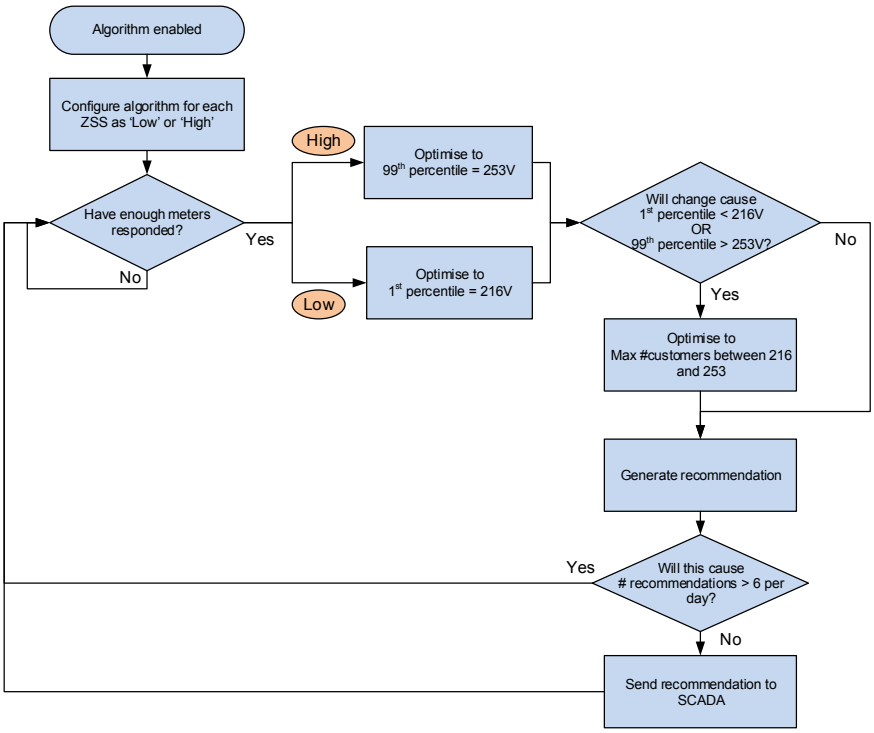


Figure 5 Algorithm Design of the Network Analytics Deployed for Dynamic Voltage Management System

3.2. SCADA Dynamic Voltage Management Application

In order to process the voltage set-point changes recommended by NAP, an application (SDVMA) was implemented in the MOSAIC SCADA system which:

- Receives messages including voltage recommendations and heartbeat from NAP;
- Validates the VRR voltage recommendations and sends them to the Master VRR at the nominated ZSS via a standard SCADA control process;
- Manages the control response from the VRR and alarms (if configured to do so) any control failure conditions;
- Maintains and updates local status records for the selected zone substation; and
- Sends updates to NAP.

There are usually multiple transformers (and therefore VRRs) at a zone substation and for SDVMA to operate at a zone substation, the transformers need to be in "Auto" mode with either transformers in "Group" mode and one transformer as "Master" and the others as "Follower" or the transformer is in "Independent" mode. The SDVMA sends a voltage set-point change to only each group in the zone substation. Table 3 explains the various configurations.

Table 3: Business Requirements for the SCADA Dynamic Voltage Management Application

No	Bus-Tie Circuit Breaker	Transformer Control Mode	Transformer Operation Mode	Transformer Operation Status	SDVMA Control Allowed
SDVMA_1	Close	Manual; only the Controller manages the voltage.	N/A	N/A	No
SDVMA_2	Close	Auto, VRR manages the voltage.	Group	Master VRR to monitor its own voltage and control accordingly[6].	Yes; SDVMA can set the voltage set-point on Master VRR.
SDVMA_3	Close	Auto, VRR manages the voltage.	Group	Follower VRR to monitor and follow the Master VRR.	No
SDVMA_4	Open	Manual; Only the Controller manages the voltage.	N/A	N/A	N/A
SDVMA_5	Open	Auto, VRR manages the voltage.	Independent, Each VRR to monitor its own voltage and control accordingly.	N/A	No

To allow a staged implementation of SDVMA, the below requirements needed to be met:

1. The SDVMA shall have "Enabled-Manual" and "Enabled-Auto" modes where Enabled-Manual mode shall display the NAP voltage recommendation (via the Operational Display and, if configured, a SCADA alarm) and allow the Controller to set the zone substation VRR request manually, while Enabled-Auto mode shall automatically send the NAP voltage recommendation to the field VRR.

[6] Note this transformer is by convention the lowest numbered transformer e.g. Transformer #1 and if Transformer #1 is out of service, then it will be Transformer #2, etc.

2. Each defined zone substation shall possess Disabled, Manual and Auto modes where:
    - Disabled mode means that no controls are sent to the VRR from SDVMA.
    - Manual means that a Controller can set the NAP voltage recommendation to the VRR and a heartbeat message will be sent.
    - Auto means that the SDVMA can automatically send the NAP voltage recommendation to the VRR and a heartbeat message will be sent.

Figure 6 shows the SCADA screen while DVMS is operating in Enabled-Auto mode at CDA zone substation.

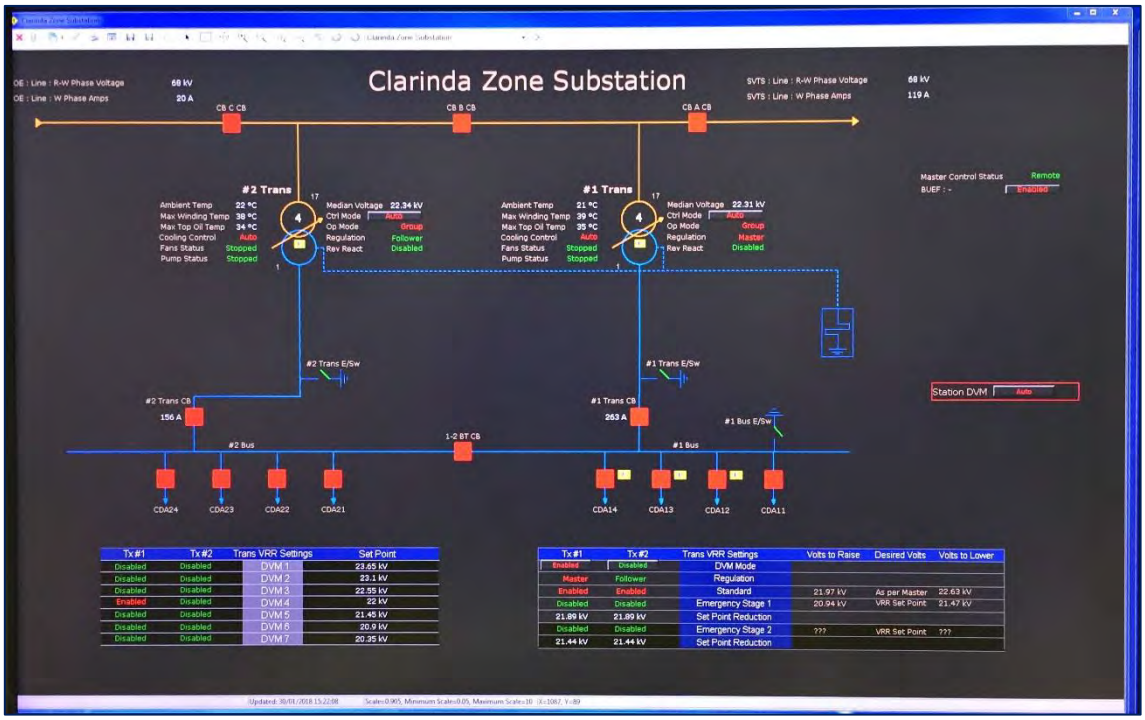


Figure 6 SCADA Screen while Dynamic Voltage Management System is Operating in Enabled-Auto Mode

3.3. Zone Substation Voltage Regulating Relays

In order to upgrade the zone substations with the highest capacity for demand response, an analysis was carried out on the performance of all zone substations and the below criteria were taken into account for prioritisation of zone substations for delivery of the construction works:

- Zone substation peak demand;
- Contribution of residential customers to the supply zone substation peak demand; and
- The first percentile of the voltage profile for all customers during peak demand.

Then, the associated works were planned to be delivered in two phases:

- Phase 1 which included 24 zone substations; and
- Phase 2 which included 22 zone substations.

3.3.1. Phase 1 of Zone Substation Works

The scope for Phase 1 was driven by the existing VRRs at each site. For the zone substations in Phase 1 there had been DRMCC-T3 and A-Eberle REG-D VRRs previously installed at the zone substation.

This phase consisted of two different high-level scopes applied across the 24 zone substations:

1. Upgrade existing Dynamic Ratings DRMCC-T3 VRRs to DR-E3 VRRs.
2. Upgrade the configuration of A-Eberle REG-D VRRs.

Both scopes required RTU reconfiguration to accommodate new SCADA input/output (I/O) associated with the DVMS.

Under the defined scope, UE coordinated with the manufacturers and suppliers to develop the base functionality required in both the DR-E3 and A-Eberle REG-D relays to implement the DVMS.

Works at DRMCC-T3 sites consisted of upgrading the unit to a DR-E3 by replacing the central processing unit (CPU) module of the transformer regulation relay. The configuration for the DR-E3 then needed to cater for the new required voltage set-points and protocol configuration. UE procured all of the DR-E3 hardware required for the upgrade from DRMCC-T3. The manufacturer (engaged by UE) was responsible for producing the configuration files for the VRRs at each specific location. The Service Provider then worked with the manufacturer to finalise the design in particular the SCADA I/O Schedule (SIOS).

Works at the REG-D sites consisted of a setting and configuration update to incorporate the new set-points and protocol configuration. The Service Provider was responsible for producing the configuration files for the VRRs. The Service Provider liaised with the manufacturer to verify those files.

The site-specific parameters were either provided by UE or retained from the existing on-site settings.

It was unacceptable for any in-service primary plant not to have complete protection coverage available at any time. However, it was acceptable to have a temporary redundant protection scheme outage where necessary. Where these outages extended beyond a day (24 hours), UE had to be advised and consulted on risk management strategies prior to the outage.

3.3.1.1 Upgrade REG-D (Functionality only)

There were no hardware or firmware changes required to upgrade the REG-D to cater for DVMS. The new DVMS set-points and controls were implemented through additional relay logic (H-code).

H-code template for DVMS was provided by UE. However, this needed to be adapted as required for some zone substations where a portion of the H-code was dedicated to cooling control. All drawings relating to H-code and relay logic were also updated to reflect the new implementation on-site.

The existing configuration only allowed for four set-points to be configured. The first three set-points catered for the normal/default and emergency set-points, all of which needed to be modified to new values which were provided by UE as part of this project. The fourth set-point was used by the custom logic to implement the additional seven set-points as summarised in Table 4 that are used by the DVMS.

Table 4: Native Set-Point Configuration (including DVMS) for the REG-D

REG-D Set-Point	UE (DVMS) Naming	Set-Point	Protocol to Enable
SP1	Static	To be modified to new values provided by UE	REGSWindex = 1
SP2	Emergency 1		REGSWindex = 2
SP3	Emergency 2		REGSWindex = 3
SP4	Dynamic Voltage Set-Point	Populated by H-Code	REGSWindex = 4

The REG-D customisation wrote each of the set-points (A21-A27) into “SP4” when controls were sent from SCADA to the corresponding digital bit (B21-B27) as shown in Table 5. The custom code also cater for the watchdog timer reset for the end-to-end DVMS.

Table 5: H-Code DVMS Set-Point Configuration for the REG-D

UE (DVMS) Naming	H-Code Analogue Naming	H-Code Digital Naming
DV0	A21	B21
DV1	A22	B22
DV2	A23	B23
DV3	A24	B24
DV4	A25	B25
DV5	A26	B26
DV6	A27	B27

3.3.1.2 Upgrade Voltage-Regulating Relays to DR-E3 (Hardware only)

Except one station at which the existing DRMCC-T3 relays were upgraded to DR-E3 relays by swapping the CPU and power supply cards in the existing chassis, all other cards in the chassis were compatible with the upgraded CPU and power supply and did not need to be amended, including wiring and external connections.

The existing DRMCC-T3 human-machine interface (HMI) was incompatible with the DR-E3 and needed to be replaced. The new HMI (named interface unit (IU) by Dynamic Ratings) connects to the DR-E3 using RJ45 copper connectors which supply power and communications to the unit. As the HMI was replaced in situ, IU extender units (supplied by Dynamic Ratings) were also required at each end to interface the new HMI with the DR-E3 as shown in Figure 7.

Figure 7 Interface Unit Extender and HMI Installed for DR-E3 Unit on the United Energy Distribution Network

The changes required to interface the new HMIs are detailed below:

- The fibre optic connector (FOC) used to interface with the existing HMI was connected to the new IU Extenders.

- At the location of the current HMI:
    - An RJ45 patch cable was connected between the new HMI and the IU Extender; and
    - The existing HMI 24Vdc power supply was connected to the new IU Extender (this unit supplies power to the new HMI).
- In the transformer equipment cubicle:
    - An RJ45 patch cable was connected between the DR-E3 IU port and the new IU Extender; and
    - A 24Vdc power supply was provisioned to the new IU Extender using the field supply available on the DR-E3 power supply card.

The configuration for the DR-E3 is not identical to the DRMCC-T3, and as a result needed to be aligned at each site with the existing configuration as part of the upgrade. The dynamic set-points also needed to be incorporated into the new configuration file. Therefore, UE engaged the manufacturer (Dynamic Ratings) to produce the new configuration files which combined the new DVMS settings (as provided by UE) and many of the existing site-specific DRMCC-T3 settings.

The default (static) set-point was equivalent to the previous set-point (float voltage set-point) at the zone substation. While the emergency set-points were configured as voltage set-point reductions in the default set-point group. The default set-point and emergency set-points needed to be modified to new values which were provided by UE as part of this project. Each other set-point, configured for DVMS, was then configured as the set-point on sequential set-point groups as shown in Table 6.

Table 6: Set-Point Configuration (including DVMS) for the DR-E3

Dynamic Ratings Set-Point Group No	UE (DVMS) Naming	Set-point (kV)	Reduction 1 (%)	Reduction 2 (%)
0	Static	Modified to new values provided by UE		
1	DV0	As prescribed by UE on a site-by-site basis	0%	0%
2	DV1		0%	0%
3	DV2		0%	0%
4	DV3		0%	0%
5	DV4		0%	0%
6	DV5		0%	0%
7	DV6		0%	0%

The set-point groups can be enabled from SCADA via protocol one at a time. To enable emergency set-points the VRR needs to be first placed into the default set-point (Set-Point Group 0) and then have a “Voltage Set-Point Reduction” applied. SCADA have been configured such that:

- Voltage reductions cannot be enabled when the VRR is not in the default set-point group; and
- Dynamic set-points cannot be enabled when voltage reduction is enabled.

It was required that all relevant drawings relating to the DRMCC-T3 to be updated to reflect the installation of the DR-E3. Where applicable, manufacturer’s drawings for new DR-E3 were sourced for the site-specific installation and inserted on UE templates.

At one zone substation, the ability to quickly disconnect the mobile transformer from the station was maintained as part of the upgrade. Also, where possible, the existing physical interface was retained or replicated similarly whilst accommodating the new requirements.

3.3.2. Phase 2 of Zone Substation Works

Phase 2 of the DVMS rollout targeted all of the remaining zone substations on the UE distribution network which had not been upgraded in Phase 1 or the Trial to accommodate the new required functionality. Each site was categorised into a series of type scopes which indicated:

1. What VRR the zone substation was to be upgraded to (DR-E3 or REG-D).
2. The required SCADA communications architecture to achieve the DVMS functionality.

All sites were considered non-standard transformer management implementations although, the existing standards for transformer management, SCADA and communications formed the basis of this scope wherever practicable to do so. The physical locations of new cubicles or equipment were specified on a site by site basis.

The secondary equipment requirements of the scope for Phase 2 were:

- Replace or upgrade the existing VRR to enable new functionality for the DVMS;
- Integrate or augment the communications architecture of the zone substation to accommodate the new or upgraded VRRs; and
- Produce new or amended relay configurations (including settings, functionality, logic and communications mappings) which incorporate the new set-points and functionality required for DVMS.

Similar to Phase 1, sites which had previously utilised DRMCC-T3 required upgrading the unit to a DR-E3 by replacing the CPU module of the transformer regulation relay. The configuration for the DR-E3 then needed to cater for the new required voltage set-points and protocol configuration, whilst retaining existing cooling control configurations. UE procured all DR-E3 hardware required for the upgrade from DRMCC-T3. The manufacturer (engaged by UE) was responsible for producing the configuration files for the DR-E3 at each specific location. The Service Provider also worked with the manufacturer to finalise the design (in particular the SCADA points mapping tables - SIOS).

Sites which had previously utilised any other VRR, or which did not have DRMCC-T3 relays installed for cooling control on all transformers, were replaced with REG-D. These schemes align closely with the current UE standard for transformer monitoring and control although, the physical layout of the equipment is non-standard for the zone substation included in Phase 2. No changes were made to the existing cooling control arrangement at these sites and the new REG-D only performs voltage regulation. The service provider was responsible for producing the configuration files for the REG-D relays.

The functionality delivered from the new VRRs as part of this project aligns with the Trial and Phase 1 of the DVMS rollout. UE confirmed all required templates, functionality and firmware as part of these projects.

The requirements for communications architecture and configuration were stipulated for each site due to the dependency on the existing arrangement and as a result:

- A new or updated SIOS was created which accommodate all required points from new or upgraded VRRs;
- A new or amended configuration was produced for the station RTU or master station interface equipment; and
- Any intermediate communications equipment (media converters, Ethernet switches, protocol converters, or similar) were approved, captured in information systems and appropriately designed.

The site-specific VRR parameters were either provided by UE or retained from the existing on-site settings.

As aforementioned in Section 3.3.1, it was unacceptable for any in-service primary plant not to have complete protection coverage available at any time. However, it was acceptable to have a temporary redundant protection scheme outage where necessary. Where these outages extend beyond a day (24 hours), UE had to be advised and consulted on risk management strategies prior to the outage.

3.3.2.1 Upgrade Voltage-Regulating Relays to DR-E3 (Hardware and Functionality)

At one zone substation the existing DRMCC-T3 relays were used exclusively for cooling control. The CPU card and HMI were then replaced. In addition, the scope outlined below were completed:

- The DR-E3 units were interfaced together using FOC and RS-485 to enable Master-Follower VRR scheme as implemented at other UE zone substations (the interconnection between the relays were marshalled at similar locations to other UE zone substations);
- The raise and lower tap controls were wired to the DR-E3; and
- Bus voltage reference (bus voltage transformer (VT)), tap position indicators (TPI) and other relevant I/Os were wired to each DR-E3 to ensure that VRR functionality can be enabled.

The legacy OLTC control was decommissioned and removed from the sit and all of the controls for the OLTC were modified to be via the DR-E3 unit.

3.3.2.2 Replace VRR with A-Eberle REG-D in a New Cubicle

The existing VRRs were replaced with the REG-Ds in a new free-standing station voltage regulation cubicle. All VRRs for the station were situated in the new cubicle, along with the new low-tension bus voltage supervision relays.

After proposing the location for the new cubicle at each site by UE, the Service Providers conducted site visits and confirmed the final location of the new station VRR cubicle.

UE's Zone Substation Secondary Design Standard – Transformer Control and Monitoring, UE ST 2002.3.09, was taken into account for the new relays with the following deviations:

(i) Panel layout was similar to the design examples shown in Milestone #4 Report.

(ii) Relay logic incorporated the H-code template for DVMS (provided by UE), similar to the Trial and Phase 1 rollout.

(iii) Remote schedule incorporated additional DVMS remote I/O points.

Similar to Phase 1, the existing REG-D standard configuration only allows for four set-points to be configured. The first three currently cater for the default/static and emergency set-points, all of which needed to be modified to new values provided by UE as part of this project. The fourth set-point is used by the custom logic (H-code) to implement the additional seven dynamic set-points required for the DVMS functionality. Figure 8 shows the new REG-D relays in a new cubicle.

Figure 8 A. Eberle REG-D Relays Installed on the United Energy Distribution Network

3.3.2.3 Replace VRR with A-Eberle REG-D on Existing Panel

This applied to the sites where there was no suitable space in the control room for a new free standing cubicle. In this case 19'' steel frame (SF) inserts, mounted onto existing steel frames in the control room, was used to house the new REG-D VRRs.

The preferred design for the 19' SF inserts is included in Milestone #4 Report. The front panel layout is similar to the design examples shown in Milestone #4 Report, except that new low-tension bus voltage supervision relays were not required.

Aside from the physical layout outlined above, this scope aligned with Section 3.3.2.2.

3.3.3. Low-Tension Bus Voltage Supervision

The previous setting range for low-tension bus voltage supervision (as prescribed in UE's Protection, Control & Monitoring Settings Standard, UE ST 2004 Clause 9.2) was not compatible with DVMS and hence, was modified as part of the DVMS rollout project. This is because the DVMS has the potential to utilise the entire +/-6% voltage range allowed at the high-voltage level, and therefore the lockout of transformer tapping by the supervision relay must be set marginally beyond this range to prevent unintended lockouts.

Under Phase 1 and 2, the low-tension bus voltage supervision relays were configured such that the limits of the voltage supervision would not impede the ability of the DVMS to augment the bus voltages via the set-point. They were also set such that they would not generate spurious alarms. Table 7 summarises the changes made on the low-tensions bus voltage supervision relays.

Table 7: Proposed Set-Points for Low-Tension Bus Voltage Supervision Relays

Supervision Setting	Existing Standard	DVMS Scope
Over-Voltage	106% of the float voltage	107% of the nominal voltage
Under-Voltage	94% of the float voltage	93% of the nominal voltage

For Phase 2, new low-tension bus voltage supervision relays were installed at the sites where the VRRs were replace with REG-D in a new cubicle. All other sites retained their existing low-tension bus voltage supervision scheme.

Where new low-tension bus voltage supervision relays were required, they were installed as per UE's Zone Substation Secondary Design Standard – Bus Voltage Supervision, UE ST 2002.3.07, with the physical location of these relays similar to the panel layout demonstrated in Milestone #4 Report. All wiring and included equipment were as per standard as practical, whilst accommodating the layout described in the relevant scope mentioned in the previous sections of this report.

The new relays have the hardwired alarms wired to either the existing station RTU or the newly installed SEL-3505-3. Figure 9 shows the low-tension bus voltage supervision relays installed on the UE distribution network.

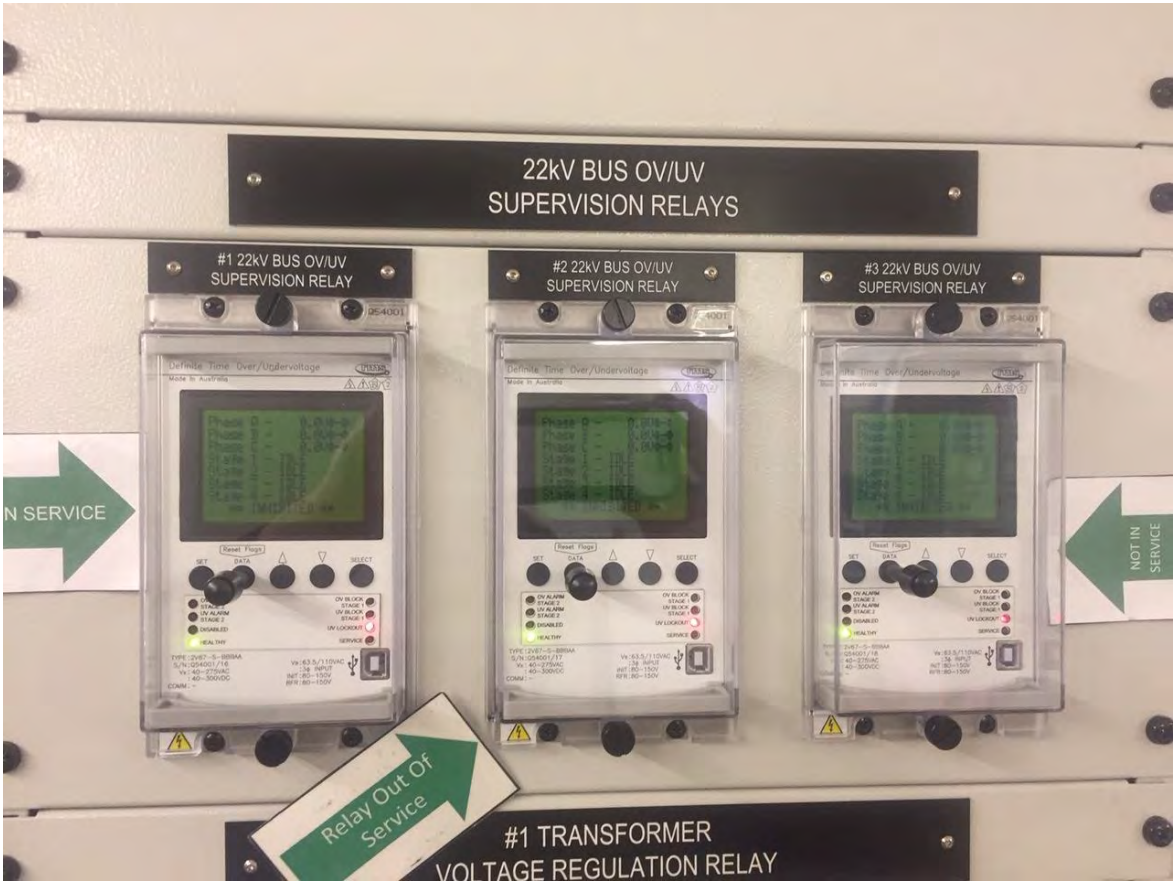


Figure 9 Low-Tension Voltage Supervision Relays Installed on the United Energy Distribution Network

3.3.4. Remote Terminal Unit

For Phase 1 at each of the locations, the station RTU which was interfaced to the station VRRs was augmented to accommodate the required controls, statuses and analogues for DVMS. These were included in the latest SIOS template provided by UE with the standard configuration files for the VRRs.

The Service Providers were responsible for updating and creating RTU configuration files, station SIOS and SEMS sheets associated with the project

Table 8 shows the voltage set-point related SCADA I/O for DVMS for DR-E3 relays.

Table 8: Voltage Set-Point related SCADA Input/Output for DVMS

Function	Quantity Names		
	Digital Input	**Digital Output**	**Analog Input**
Active Set-Point	N/A	N/A	Dynamic Voltage Active Set-Point
Static Set-Point	DVM Mode	DVM Mode Disable	VRR Set-Point
Emergency Off[7]	VRR Standard Operation	VRR Standard Operation Enable	N/A
Emergency 1	VRR Emergency Stage 1	VRR Emergency Stage 1 Enable	VRR Emergency Stage 1 Set-Point
Emergency 2	VRR Emergency Stage 2	VRR Emergency Stage 2 Enable	VRR Emergency Stage 2 Set-Point
DVMS Set-Point 1	Dynamic Voltage Level 1	Dynamic Voltage Level 1 Enable	Dynamic Voltage Level 1 Set-Point
DVMS Set-Point 2	Dynamic Voltage Level 2	Dynamic Voltage Level 2 Enable	Dynamic Voltage Level 2 Set-Point
DVMS Set-Point 3	Dynamic Voltage Level 3	Dynamic Voltage Level 3 Enable	Dynamic Voltage Level 3 Set-Point
DVMS Set-Point 4	Dynamic Voltage Level 4	Dynamic Voltage Level 4 Enable	Dynamic Voltage Level 4 Set-Point
DVMS Set-Point 5	Dynamic Voltage Level 5	Dynamic Voltage Level 5 Enable	Dynamic Voltage Level 5 Set-Point
DVMS Set-Point 6	Dynamic Voltage Level 6	Dynamic Voltage Level 6 Enable	Dynamic Voltage Level 6 Set-Point
DVMS Set-Point 7	Dynamic Voltage Level 7	Dynamic Voltage Level 7 Enable	Dynamic Voltage Level 7 Set-Point
DVMS Fail[8]	Dynamic Voltage Health	N/A	N/A

For sites which already had the capability to manually override the Group/Independent mode of the VRR, this will no longer be available on the new VRRs. These controls were removed from the SIOS and RTU configuration for the site.

For Phase 2, the configuration for the RTU aligned with the configurations implemented as part of the Trial and Phase 1 of the DVMS rollout. A SIOS was either produced or amended for each site incorporating the points required to implement the DVMS functionality.

Two different scopes, depending on the previous configuration of RTUs, were implemented for Phase 2 which are outlined below.

3.3.4.1 Augment Existing Remote Terminal Unit

Similar to Phase 1, the existing RTU was reconfigured to cater for the new I/O required for the DVMS scheme. All points and functionality then aligned with the DVMS Trial and Phase 1 sites.

[7] This only applied to the DR-E3 configuration, these indications were not required for the REG-D relays.
[8] This was subject to the capability of each of the relays to signal that the relay had timed out to return to the static set-point and would be taken into consideration for future improvements.

New equipment was only connected using DNP3 over IP. At some sites the existing RTU which had not had an existing master DNP over IP session configured, this was added to the RTU with all relevant mapping tables and configuration completed for the new session.

The existing station SIOS was then updated to include all new digital inputs, outputs and analogue inputs associated with the new configuration. Where existing relays were upgraded, their existing point maps were updated to incorporate the new points. While where new relays were installed, the new equipment were added to the existing RTU as a new DNP slave. The Service Provider provided the updated station SIOS and logic requirements to UE, who was responsible for producing revised configuration files for existing RTUs.

3.3.4.2 Install a SEL-3505-3 as the Host Interface for the VRRs

Where the existing RTU was unable to accommodate the new VRR, a SEL-3505-3 acted as the host interface for the VRRs. In most locations this acted as a like-for-like replacement of the MD3311 OLTC RTU which was directly interfaced to the SCADA host. However, sites which previously interfaced via a SEL-2032 using MODBUS also have a new SEL-3505 added for the VRRs.

The SEL-3505-3 has a new SIOS created for the SEL-3505-3 with all points associated with the VRRs connected as per the standard, plus additional DVMS points. This has all I/O over protocol, except for hardwired relay fail alarms which were grouped with existing Station X/A Device Health alarm.

Figure 10 shows one of the SEL-3505-3 installed as the Host Interface for the VRRs on the UE distribution network.

Figure 10 SEL-3505-3 Installed as the Host Interface for the Voltage Regulating Relays

Where a new cubicle was installed, the new SEL-3505-3 was physically located in the new VRR cubicle similar to the design examples shown in Milestone #4 Report.

For sites which required a new SEL-3505-3 but did not have a new VRR cubicle the location for the SEL-3505-3 was specified separately. It was assumed that the side plane of the communications cubicle at each site could be used to mount the equipment.

3.3.5. Station Communications Architecture

The changes made on the station architectures under the DVMS rollout project were dependent upon the existing communications hardware onsite, and the spare capacity available to accept new equipment. The station architectures for the connection of the new or upgraded VRRs are listed below.

3.3.5.1 Standard Architecture

Architecture implemented was, as per UE's Zone Substation Secondary Design Standard – SCADA & Communications, UE ST 2002.4.

For the station with standard architecture, all VRRs were directly interfaced to the station local area network (LAN) switch which shares its bus designation. The VRRs are polled by the station RTU which is polled by the host.

At sites with an architecture similar to the standard but not fully compliant, the existing architecture was minimally amended to accommodate the new equipment.

3.3.5.2 Legacy Architecture (Serial Fibre)

The existing serial fibre was not extended for the network sites which had a legacy architecture utilising serial fibre via star-couplers to provide SCADA connectivity to intelligent electronic devices (IEDs) as demonstrated in Figure 11.

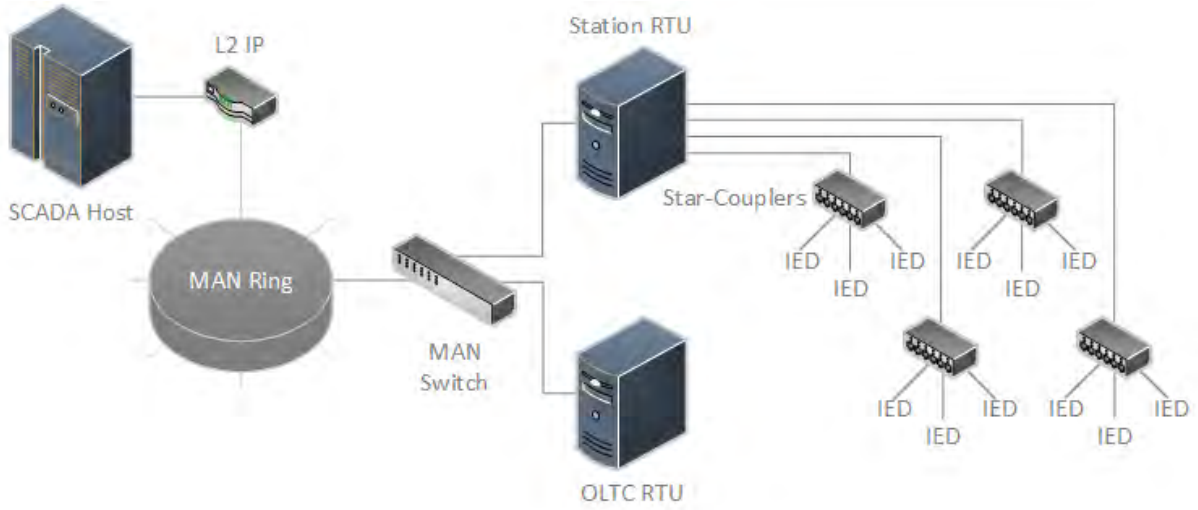


Figure 11 Existing Serial Fibre Communications Architecture

To interface the new IEDs to the station RTU a new station LAN was established by extending the MAN switch at these sites as shown in Figure 12. The following changes were required to implement the new architecture:

- Installation of a new module (MM3-4FXM2) on the existing station metropolitan-area network (MAN) switch; and
- Connecting the new VRRs to the new module on the MAN switch.

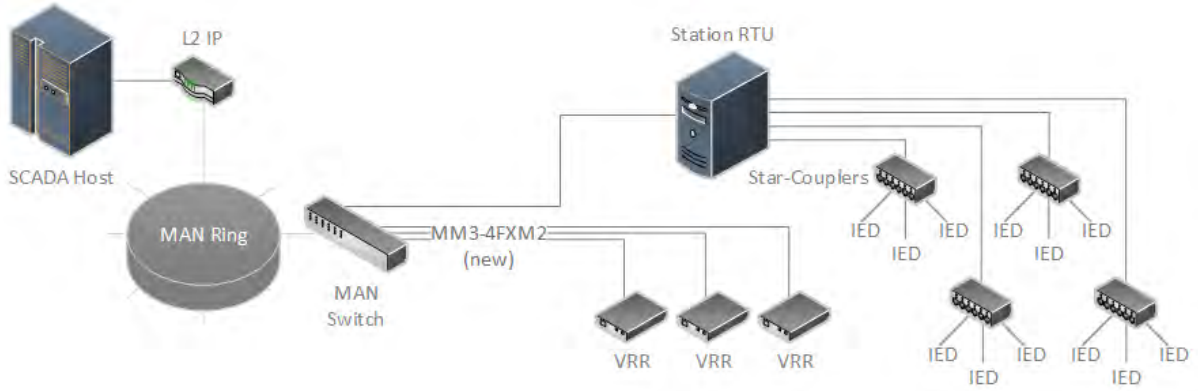


Figure 12 New Communications Architecture with Voltage-Regulating Relays Added

3.3.5.3 SEL-3505-3 as OLTC RTU Replacement

The VRRs were connected to the SCADA host as a like-for-like replacement of the previous OLTC RTU at sites which had an incompatible station RTU (MD1000 and SEL-2032). The existing architecture for these sites is demonstrated in Figure 13.

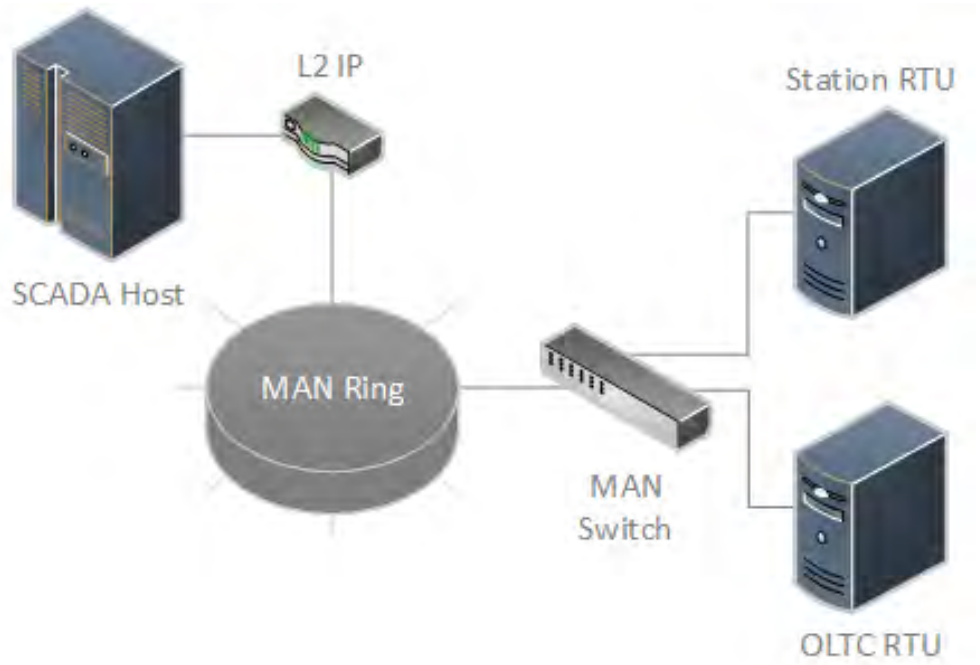


Figure 13 Legacy Communications Architecture with Hardwired, Copper Serial or Proprietary Protocol Downstream of the Station Remote Terminal Unit

Where the interface for the existing VRR was to a SEL-2032 via MODBUS the new VRR was connected via a new SEL-3505-3. If the previous VRR also performed cooling control, the MODBUS connection to the existing relay remained in service to provision SCADA connectivity for the cooling functions.

The new architecture required:

- Installation of a new SEL-3505-3 which acts as the RTU interface for the VRRs;
- Installation of a new module (MM3-4FXM2) on the existing station MAN switch; and
- Connecting the new VRRs to the new module on the MAN switch.

Figure 14 demonstrates the new communication architecture for these sites.

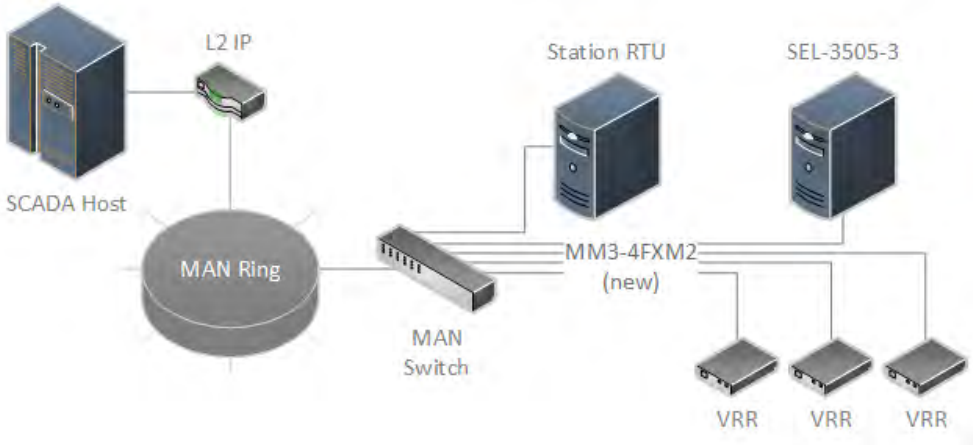


Figure 14 New Architecture with Voltage-Regulating Relays Communicating via a SEL-3505-3 to the Host

3.3.5.4 Remote input and output

Remote I/O was implemented in strict accordance with UE's Zone Substation SCADA I/O Schedule (SIOS) template, UE ST 2140.

Additional, non-standard, remote I/O points needed to be added to the SIOS in order to cater for the DVMS functionality. The SIOS template, UE ST 2140, was then updated by UE with new standard remote I/O points for DVMS (REG-D and DR-3 options). These new DVMS remote I/O points are very similar to what was installed at CDA zone substation as part of the DVMS Trial, and in general they consist of the following:

- A status (enabled/disabled) point for each new voltage set-point;
- A control enable point for each new voltage set-point;
- An analogue value returning the set-point voltage for each new set-point; and
- An analogue value returning the current active set-point voltage for the VRR.

Naming conventions and functionality for these points depend on whether the new VRR is a DR-E3 or REG-D as summarised in Table 8.

3.3.5.5 Time Synchronisation

Time synchronisation for the new VRRs and communications equipment is described below (in order of priority).

1 Local station GPS clock directly using SNTP[9] via the station LAN.

2 Local station GPS clock via the station RTU using SNTP (when station time synchronisation is via IRIG-B).

3 Upstream network time servers using SNTP (liaise with UE SCADA team to confirm target).

4 SCADA Host time synchronisation using DNP.

[9] SNTP = Simple Network Time Protocol.

4. Performance Improvement

The main driver for DVMS is to be able to dynamically move the voltage profile of each zone substation on the UE distribution network toward the lower limit of 216V ($V_{1\%}$) that is defined in Australian Standard 61000.3.100-2011 in order to deliver demand response service to minimise any customers outside of the stipulated regulatory limits.

Without implementing the LV remedial works, the voltage profiles for different UE's zone substations would have experienced under-voltage and over-voltage operating conditions when the operation mode of DVMS was changed from $V_{99\%}$ (253V) to $V_{1\%}$ (216V) or vice versa. In order to successfully deliver the required demand response level (30MW) via DVMS, the load profile of network was required to be altered to become 'taller' and 'narrower' to allow for the tap changes at zone substations to occur and the customers to remain within the voltage limits. This goal was achieved by conducting a series of LV network works including changing the tap settings of distributions transformers, load balancing, relocating LV open points, network augmentation and connection checks.

Figure 15 and Figure 16 depict the LV network voltage profile averaged across all UE zone substations at time of maximum demand during summer 2018/19 prior to and post implementation of these LV remedial works, respectively. The voltage profiles were obtained by averaging the voltages at 5:00pm EDST on 4 days where the temperature was above 35°C.

Figure 15 indicated that UE had a legacy steady-state voltage compliance issue at maximum demand which was only revealed (and could only be fixed) since the visibility provided by the smart meter rollout programme. This issue is likely to be common across all distribution networks in the NEM and stems from the lack of visibility of LV network voltages and the cumulative effects of this since the construction of the networks during the 20th century.

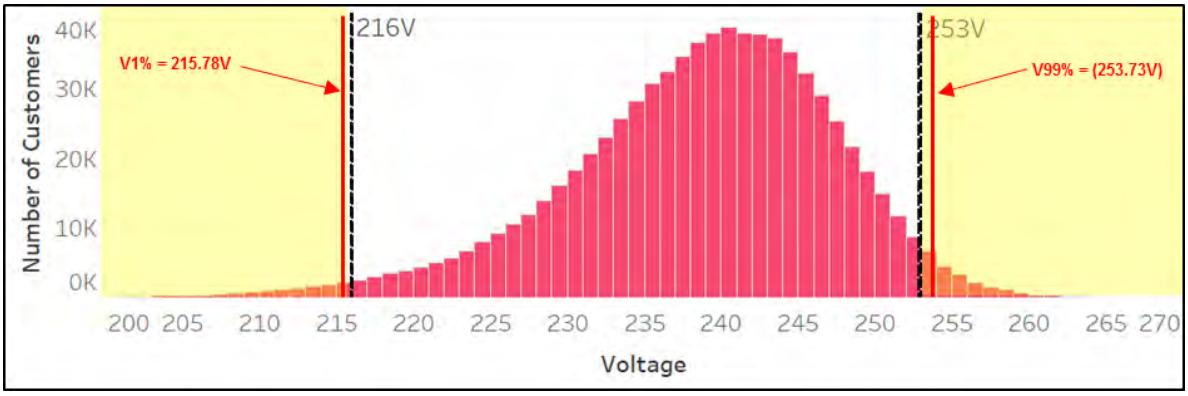


Figure 15 Voltage Profile of the UE Distribution Network Prior to LV Remedial Works (Peak Demand)

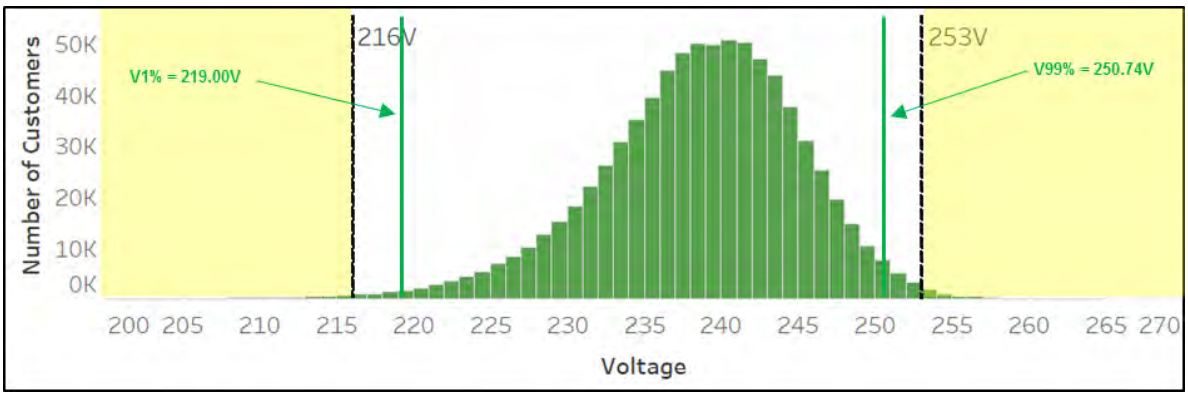


Figure 16 Voltage Profile of the UE Distribution Network Post LV Remedial Works (Peak Demand)

Figure 16 highlights the total effect of the LV remedial works performed (tap changes at distribution transformer level, load balancing, etc.) has had on the network. As observed, the tails of the bell curve are now shorter in length, with more customers being pushed into the middle of the range. The LV remedial works have made UE's population of LV voltages not only compliant with AS 61000.3.100-2011, but provided the additional margin needed to provide voltage reduction demand response capability.

Table 9 summarises the impact of these LV remedial works on voltage profiles across the selected 4 peak demand days.

Table 9: Network Voltages across 4 Peak Demand Days

Parameter	Prior to LV Remedial Works	Post LV Remedial Works	Improvement	
			(V)	(%)[10]
V1%	215.78V	219.00V	3.22	1.40
V50% (Median)	238.90V	238.32V	–	–
V99%	253.73V	250.74V	2.99	1.30
TOTAL	–	–	6.21	2.70

Voltage spread is calculated as the difference between the 99th percentile value ($V_{99\%}$) and the 1st percentile value ($V_{1\%}$).

For multiphase sites, the reported voltage spread is the maximum of the voltage spread values across all phases. For LV sites, it is expressed in percent of nominal voltage of 230V.

From demand response perspective, a lower value means better performance as it will indicate a narrower voltage profile for the zone substation. The voltage spread is a good indicator of how the voltage distribution of each zone substation has been reduced in width, which in turn, allows DVMS to better shift the distribution up or down as required. Initially, a targeted $V_{1\%}$ value of 223V was established for LV remedial works, while $V_{99\%}$ remained 253V, to allow a voltage reduction margin down to $V_{1\%}$ of 216V for RERT.

Therefore, the targeted spread value for each zone substation at peak demand was 30V (253V-223V), compared to the allowed spread as per the Code of 37V (253V-216V).

Only a subset of distribution substations from the total population needed to be targeted for LV remedial works to achieve this result.

As shown in Table 10, the voltage spreads at all remediated distribution transformers have improved after the LV remedial works were implemented.

Table 10: Impact of LV Remedial Works on Voltage Spread on the UE Distribution Network

Voltage Spread	Prior to Implementation of LV Remedial Works	Post Implementation of LV Remedial Works	Improvement	
			V	(%)[11]
Median	38.22V	32.05V	6.17	16.14
Maximum	45.67V (RBD)	36.64V (NW)	9.03	19.77
Minimum	28.85V (DSH)	20.83 (DSH)	8.02	27.80

According to Table 3, the voltage spread across the zone substations from the remedial works decreased by 6.17V with the greatest improvement occurring at Rosebud zone substation (RBD), with the voltage spread being reduced

[10] The reference is the nominal voltage of 230V.
[11] The reference is the initial value.

by 14.39V. Surrey Hills (SH) zone substations had the least improvement where the voltage spread decreased by only 0.29V.

Table 11 also summarises the improvement of voltage spread from the LV remedial works with respect to the number of zone substations.

Table 11: Voltage Spread Improvement – Zone Substation

Voltage Spread	Zone Substation		Improvement
	Prior to Implementation of LV Remedial Works	Post Implementation of LV Remedial Works	
≤ 37V (Allowed Voltage Spread)	33%	100%	67%
≤ 35V	13%	89%	76%
≤ 30V (Targeted Spread)	4%	20%	16%
≤ 25V	0%	2%	2%

On average, the voltage spread before was 37.95V which fell to 31.74V after the LV remedial works, a decrease of approximately 16.36%.

For more information on the impact of conducted LV distribution remedial works, refer to Milestone #5 Report.

5. Lessons Learnt

5.1. Operational

5.1.1. Full Activation Timing Delay

UE was unable to achieve the full 30MW in the first half hour interval during the 4th AEMO test on 27th November 2018 due to a data bandwidth bottleneck problem encountered between the analytics engine/data warehouse (NAP/OSI PI) and the real-time SCADA system (MOSAIC). This resulted in a slower than normal tapping down of transformers as NAP did not have up-to-date information to drive transformer taps faster during the activation, with the transformers still tapping down even during the first half hour of the event period. This delay effect from the data bottleneck diluted the demand response delivered in the first half hour period.

An example of this delay in tapping is shown in Figure 17.

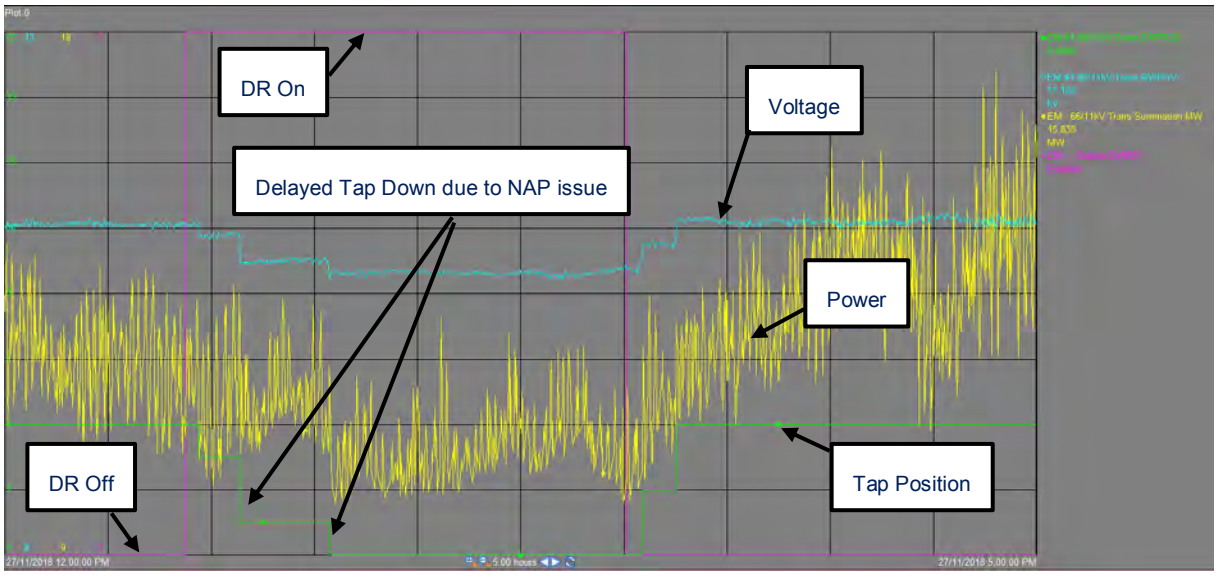


Figure 17 Test Showing Delayed Tapping Issue

The delayed tapping down is clearly evident with three tap change steps over a period of 40 minutes.

This issue was promptly identified and rectified subsequent to the AEMO test by increasing the data capacity between the systems and fine-tuning the activation algorithm in the analytics engine. The changes were retested on 10th December 2018, resolving the delay issue. The same site (East Malvern) is used to present the results of the rectification (on the same time scale), showing a substantial improvement in tapping performance as demonstrated in Figure 18.

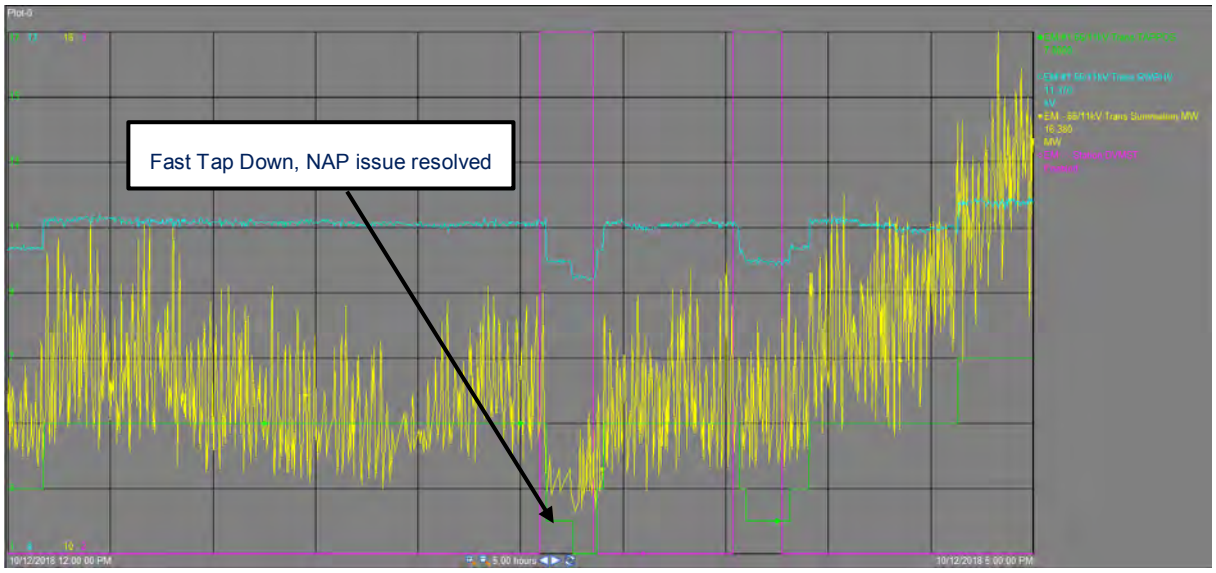


Figure 18 Test Showing Delayed Tapping Issue Resolved

The tapping down is now clearly much faster, reducing to two tap change steps over a period of 10 minutes.

5.1.2. End of Tapping Range

The 4th AEMO test which was conducted during a period of light load revealed a possible limiting factor in the performance of the system. The magnitude of the demand response available during light load periods is limited not only by the magnitude of the low demand itself, but also from available tapping range of many zone substation transformers. Under light load, transformers typically operate closer to the bottom end of their tapping range, which could limit the size of the voltage reduction available. This is clearly illustrated in the EM example above, where the tap change from normal operation to demand response operation went from tap 5 down to tap 1 (the bottom tap).

This end of tapping range limitation is however not expected to be applicable at periods of high demand, with transformers likely to be operating much higher in their tapping range to cater for voltage drops through the network. This is illustrated in Figure 19 over a period of 4 days when a high demand day was experienced on 7th December 2018. For the EM example below, the taps are likely to be operating around tap 8 compared to tap 5 on a low demand day. This provides an additional voltage margin for demand response of 3 taps x 1.025% step = 3.1%.

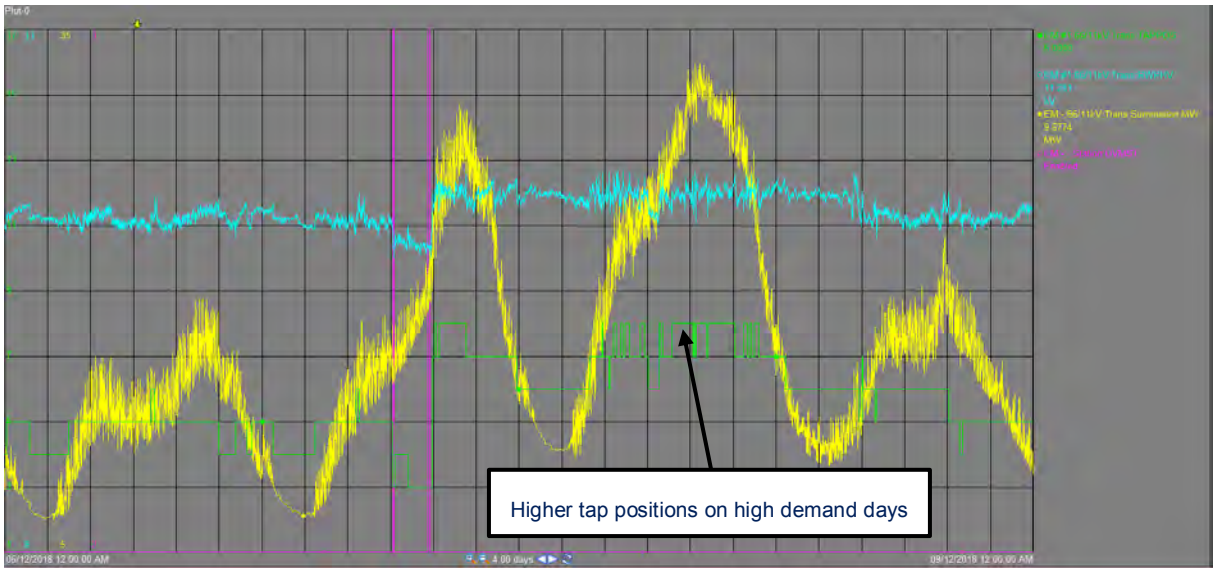


Figure 19 Greater Tapping Range Available for Demand Response on High Demand Days

On such days, the voltage reduction would be limited not by the tapping range, but by the available margin from the spread of customer voltages, which can be controlled through the LV network remediation works presented in Milestone #3 Report.

This information is useful in developing up a capability diagram for the operation of the DVMS which is discussed in Milestone #5 Report.

5.1.3. Baseline Accuracy Assessment and Review

The assessment of the demand response delivered is highly dependent on the baseline method selected, particularly in instances where the shape of the daily demand changes from day to day. In UE's case, the major contributor to the shape of the daily demand curve is the ambient temperature. This is illustrated below and shows how the default AEMO baselining method (Method 1) is inappropriate for UE's demand curve and can result in substantial overestimation or underestimation of the demand response delivered.

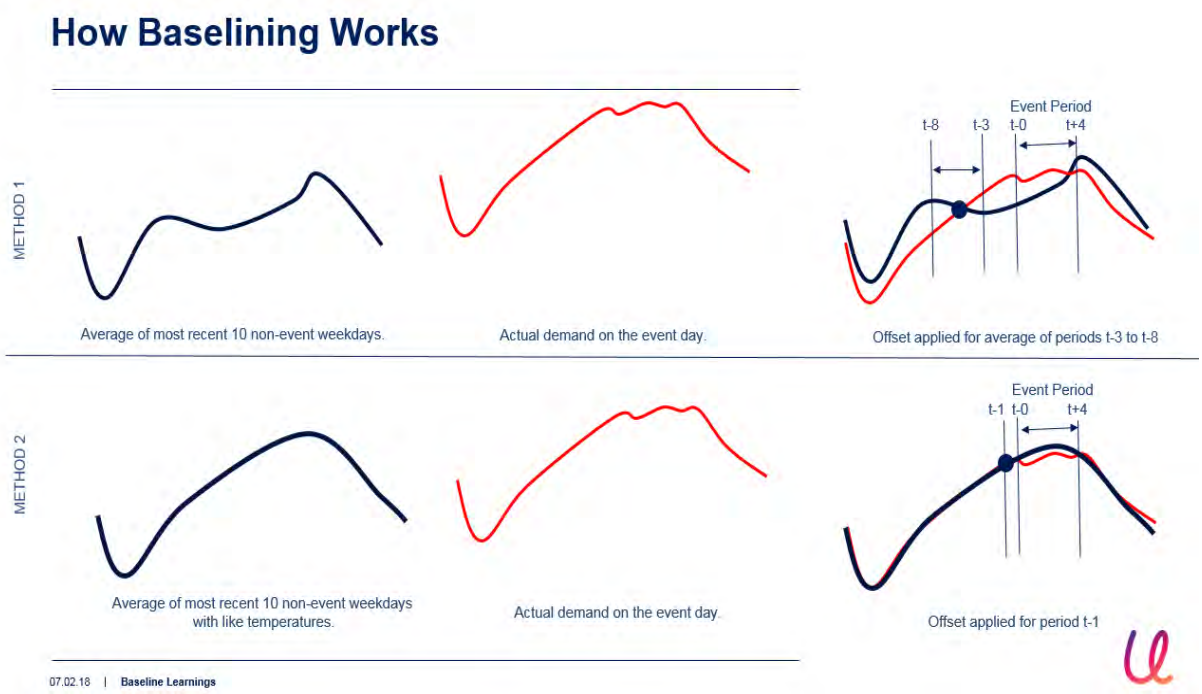


Figure 20 Suitability of Baseline for UE's demand (Method 1: AEMO Default, Method 2: UE Proposed)

For mild-temperature days (which could dominate the 10 non-event days prior to the event day), UE's weekday daily demand shape resembles as per the top-left profile. If an event is called in the middle of a hot day (and assuming UE delivers the required demand response), the daily demand shape resembles the top-middle profile.

The default AEMO baselining shown in Method 1 essentially takes these two curves and pegs them together at the average of a number of periods before the event start time. When this is done, the curves shown in top-right is ambiguous of what level of demand response is actually being provided.

In recognition of this problem, AEMO and UE agreed to pursue the merits of an alternative baselining method.

UE proposed a baseline method shown in Method 2 which only chooses like-temperature non-event weekdays in recent past shown bottom-left, but also pegs the curves at one time interval prior to the event start shown bottom-right. Clearly this provided a much better comparison to estimate the actual demand response delivered and this can be seen by the gap between the curves at any point in time.

AEMO and UE ultimately negotiated a position on the preferred baseline method based on the following principles:-

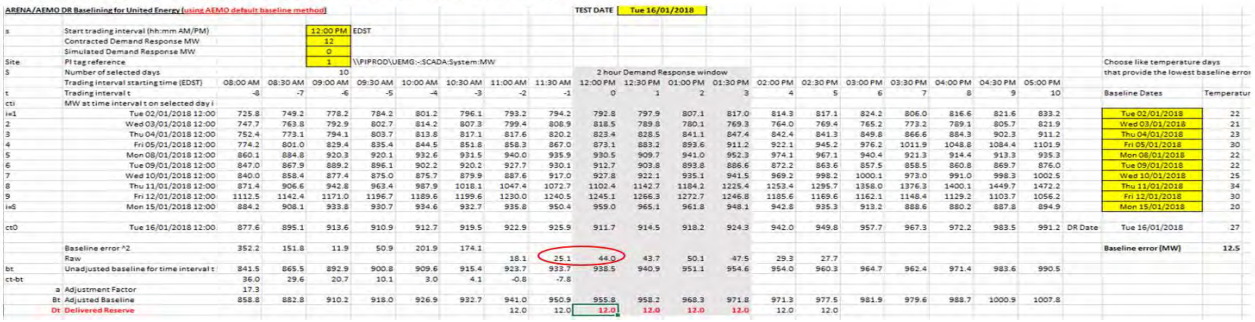
1. the qualifying baseline days (for the like-temperature days) are to be the most recent 10 non-event, non-holiday, weekdays with maximum temperatures within the band of +4°C to -4°C of the activation day;
2. The period of time to select qualifying days for the 10 day baseline is limited to one year. Given the temperature range, this should allow sufficient time to obtain qualifying days but if it doesn't, the +/-4°C variance will need to be violated to include temperatures lower than the 4°C bottom band;
3. The temperature to be measured at Bureau of Meteorology station Moorabbin Airport station number: 086077; and

4 The event day adjustment will be retained (as per the default baselining method) because the suggested single trading interval before activation is subject to being too heavily influenced by the conditions at activation time and any setup by the service provider. The original trading intervals should still maintain sensitivity for temperature without being unduly influenced by temporal anomalies.

The UE analysis of the 16th January 2018 test day using the three baseline methods (i.e. AEMO default, UE proposed, and AEMO-UE negotiated) are presented in Figure 21 and Figure 22.

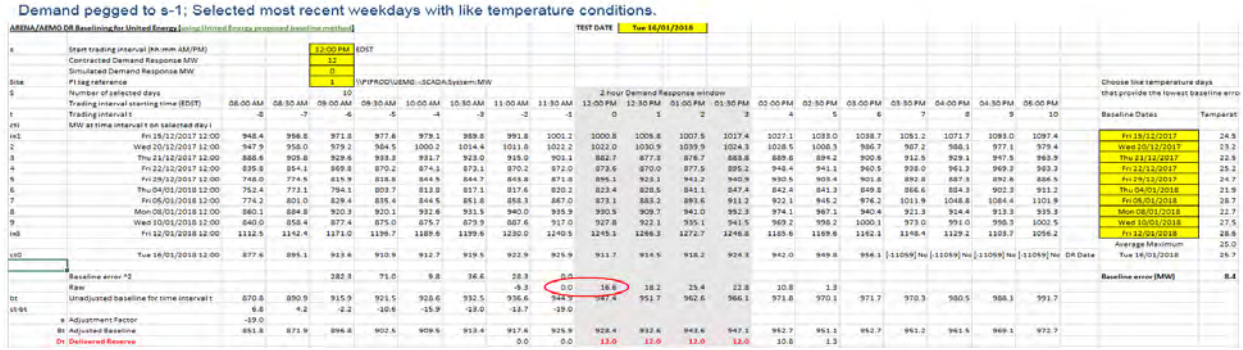
AEMO Original Baseline Method

Demand pegged to average of s-3 to s-8. Selected most recent weekdays.



UE Suggested Baseline Method

Demand pegged to s-1; Selected most recent weekdays with like temperature conditions.



AEMO Agreed Baseline Method

Demand pegged to average of s-3 to s-8; Selected most recent weekdays with like temperature conditions.

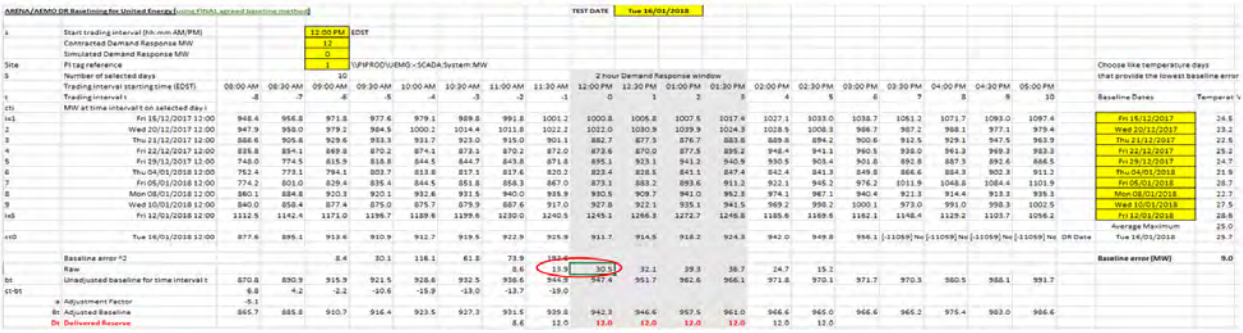


Figure 21 Comparison of Baseline Assessments for the 16th January 2018 Test Event

Company	UNITED									
Contract ID	RB006									
Activation Date	16/01/2018									
Activation start time	1100	(NOTE: time is Eastern Standard Time)								
Activation finish time	1300									
Was this a test	YES									
Contracted MW capacity	12									
Benefiting region	VIC									

Test Results										
	Pre-test interval 2	Pre-test interval 1	Test interval 1	Test interval 2	Test interval 3	Test interval 4	Test interval 5	Test interval 6	Post test interval 1	Post test interval 2
Adjusted baseline MWh	467.953904	472.0851	473.3081822	475.330389	480.6788906	482.3103281	484.6229	483.0969	482.9078	481.2611
Actual demand MWh	463.644675	465.2658	458.731339	459.81689	461.812919	464.779184	473.4895	477.5471	481.0535	485.8969
Delivered reserve MWh			14.57684315	15.51349895	18.86597155	17.53114405				
Calculated MW delivery			29.1536863	31.0269979	37.7319431	35.0622881				
Shortfall (MW)			0	0	0	0				

Average MW delivery during test period	33.2437289

BASELINE DATES
12-Dec-2017
15-Dec-2017
20-Dec-2017
21-Dec-2017
22-Dec-2017
29-Dec-2017
04-Jan-2018
08-Jan-2018
10-Jan-2018
12-Jan-2018

Figure 22 AEMO Assessment of the 16th January 2018 Test Event Using the Negotiated Baselining Method

These results are summarised in Milestone #2 Report.

5.1.4. DVMS Demand Response Capability

UE has undertaken sufficient demand response tests and RERT live events now over a wide range of network demand to start to develop a capability diagram of the DVMS in being able to deliver demand response. The diagram can be presented in Figure 13.

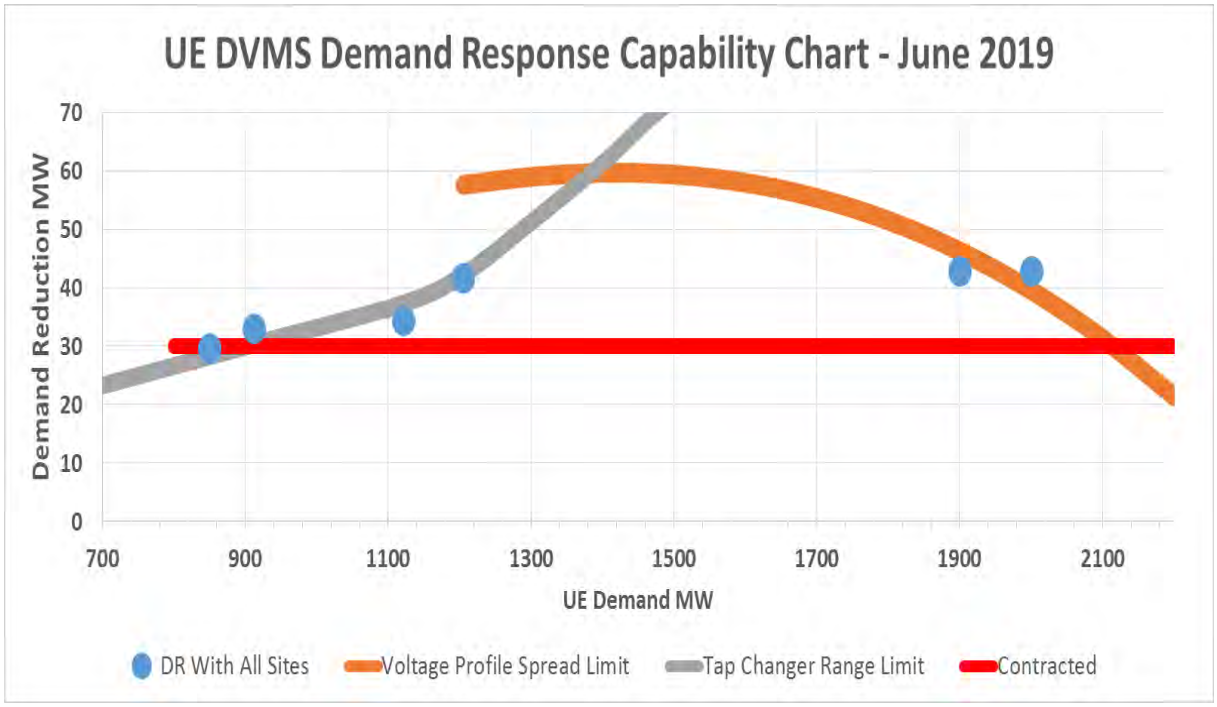


Figure 23 UE DVMS Demand Response Capability Diagram

Overlayed on the chart are the event results (in blue) for which customer voltages are maintained within AS 61000.3.100, and the AEMO contracted demand response requirement for UE (in red).

It can be observed that the magnitude of the demand response at low demand levels is limited by the available buck tap positions on the fleet of zone substation transformers (indicated by the grey line), whereas at high demand levels, the magnitude of the demand response is limited by the spread of customer voltages across the fleet of smart meters at each zone substation (indicated by the orange line).

The constraint equation for the customers' voltage-profile spread limit which is a reflection of the voltage drops which occurring through the distribution network as a result of network impedances can be approximated by:

DR_{MW} (voltage profile spread limit) = UE $Demand_{MW}$ * $dP/dV_{\%/\%}$ * (216v - V1%v) / 230v

where dP/dV is the elasticity of active power to voltage (refer to Milestone #2 Report) = 0.69 %/%.

The constraint equation for the zone substation tap range limit is a reflection of the available tap positions on the zone substation transformers can be approximated by:

DRMW (tap range limit) = UE $Demand_{MW}$ * dP/dV%/% * (tap# - 1) * 1.25%

where tap# is the average tap position at the UE $Demand_{MW}$ and 1.25% is the transformer tap step size.

5.1.5. Over-Voltage Alarms Generated by Zone Substation Bus Supervision Relays

Traditionally, on hot days when the demand on the network increases, some customers in particular the ones located at end of the LV circuits receive under-voltages due to the voltage drop along the supplying circuits. As a result, the DVMS using the feedback from all AMI meters supplied by the zone substation will send a command to select a higher voltage set-point of the VRRs at the zone substation.

This results in selecting the highest voltage set-point by the DVMS for majority of 11kV and 6.6kV zone substations. The highest voltage set-points, Dynamic Voltage Level 1, for 11kV and 6.6kV zone substations are set to 11.66kV (11kV +6%) and 7.00kV (6.6 +6%), respectively.

Whenever a 11kV or 6.6kV zone substation is operating at Dynamic Voltage Level 1, bus over-voltage alarms were likely to be triggered because of the combined effects of:

- Voltage regulation bandwidth (typically 1%);
- Phase unbalances (typically 0.5%);
- Measurement accuracy of bus supervision relays (typically 0.5%); and
- Measurement discrepancies between the two or three low-tension bus voltage transformers (VTs) (typically 0.5%).

Hence, this caused a larger number of over-voltage alarms received during the 2018/19 summer. These nuisance alarms caused inconvenience and confusion for the Network Control Centre and needed to be minimised.

Proposed Solution

Prior to implementing the DVMS, the over-voltage settings of bus supervision relays for 11kV and 6.6kV zone substations were set to +6% of float voltage setting rather than +7% of the nominal voltage.

Since the overwhelming majority of the 11kV zone substations had voltage regulation set-points (float voltages) greater than 11.31kV prior to the DVMS, therefore it was proposed to relax the over-voltage supervision set-point to +9% of the nominal voltage which would be 12kV. The proposed over-voltage set-point of 12kV was no higher than the previous values. The only exceptions were Bullen (BU), Elsternwick (EL) and Mentone (M) zone substations, which would see slight increase in over-voltage set-points.

For the 6.6kV zone substation (Surrey Hills) it was proposed to deploy the over-voltage set-point of 7.26kV which had previously applied to the bus supervision relays. This set-point was equal to 10% of the nominal voltage of 6.6kV.

Relaxing the over-voltage supervision set-points to +9% (for the 11kV zone substations) and 10% (for the 6.6kV zone substation) resulted in reducing most, if not all, the nuisance over-voltage alarms that had been received on hot days.

5.1.6. Over-Voltage and Under-Voltage Warning Alarms

The Network Control Centre received a large number of voltage-related warning alarms for some zone substations when the DVMS was commissioned. These alarms were triggered on percentages above nominal voltages (±5%)

rather than the previous float voltages. The warning alarms were problematic when the DVMS was switched off or operating during high-demand periods when the voltage on the network was boosted. Therefore, it was concluded that there was no value in using such alarms for a voltage that was well within the Code limits and the alarms were removed from SCADA. The SCADA over/under operating alarms are still operational.

5.1.7. High-Voltage Customers Complaints

Part of the DVMS Trial was to study the impact of dynamically regulating the voltage, in particular under-voltages, on HV customers, all of the HV feeders supplied by Clarinda (CDA) zone substation were modelled in PSS/SINCAL as described in Milestone #2 Report. According to the modelling results, in a peak demand day V_{sp7} (the lowest dynamic voltage set-point) was the only voltage-set-point that would cause under-voltages received by the HV customer. However, this voltage set-point was not defined for peak demand days. Therefore, it was concluded that rolling out the proposed dynamic voltage set-points onto the UE's zone substations would not cause any under-voltage issues for HV customers.

However, as a result of switching the DVMS from power quality mode to demand response mode during peak demand times, some HV customers contacted the Network Control Centre and informed UE that they received under-voltages and consequently, their protection devices either tripped or alarms. This occurred due to lack of UE's visibility on the supplying voltage levels to these customers given the absence of smart meters at these sites. While the DVMS takes the feedback from the AMI meters located adjacent to HV customers into account to generate voltage set-points for the supplying zone substation, some investigations were undertaken to ensure such HV customers would not receive any non-compliant voltages. After reviewing the voltage measurements captured by customers' monitoring devices, it was found that the received voltages were within the Code limits as shown in Figure 24.

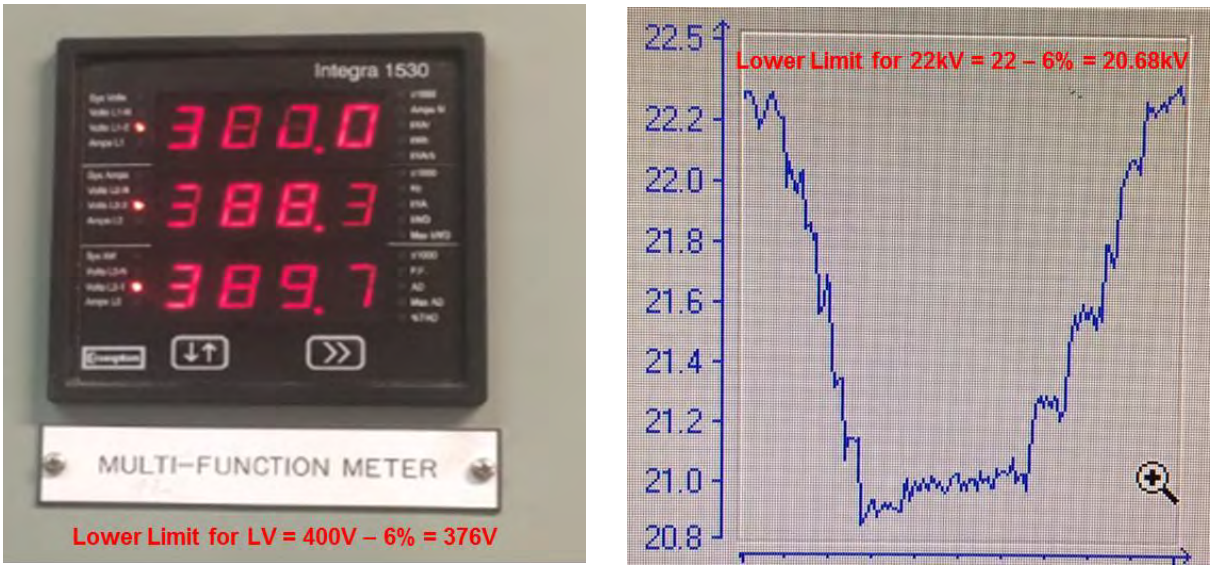


Figure 24 Voltage Readings by HV Customers' Monitoring Devices During Demand Reduction Mode of UE's DVMS

Therefore, it was suggested to the impacted customers to revisit their protection settings and set them to alarm only when the voltage excursions go beyond the limits of the Code. Also, to assist those customers, some adjustments were applied onto the NAP voltage threshold settings (maximum and minimum). Since then, UE did not receive any customer complaints in this regard.

5.1.8. Modify Default Voltage Set-Points at Zone Substations

Since the default voltage set-points of VRRs had typically been selected based on high network loading conditions on the distribution network, they were relatively higher than the nominal voltages. This resulted in over-voltages received by the customer most of the time when the network load was not very high.

Since the operational of the DVMS at all of the zone substations, the default voltage set-points will be used only when there is a network abnormal operating condition such as opening the bus-tie circuit breaker. Due to the design

of DVMS by disabling the scheme, the transformers will revert back to the default voltage set-points and they might need to perform a few tap changes.

Therefore, to minimise the number of tap changes as a result of this switching, it was recommended to modify the values of default voltage set-points to the most common dynamic voltage set-points. In that case, if a bus-tie circuit breaker is opened, a tap change will not be required in most of the time. It will reduce the risk of shortening the life of OLTCs.

It should be noted that the new values for the default voltage set-points were selected after analysing the smart meter data for the zone substation.

5.1.9. Reduce the Step between Dynamic Voltage Set-Points

After trialling the DVMS for the first time on the UE distribution network, 2.5% was selected as the step between dynamic voltage set-points at the time of commissioning. Based on the tests conducted on the Trial, it was recommended to revisit this step and also the voltage settings before rolling out the scheme on the network. It was expected that a smaller step (e.g. 1.5%-2%) would assist NAP to generate smoother voltage recommendations and as a result, manage the voltage swells and sags due to switching of terminal station/zone substation capacity banks. Consequently, 2% was deployed across the distribution network and this modification improved the performance of the DVMS.

5.1.10. Proceduralise Network Abnormal Operating Conditions

In some network abnormal operating conditions, it would initially be easier to disable the DVMS scheme manually prior to performing any switching. In this way, the unnecessary complications imposed to the NAP algorithms would be avoided. Therefore, the relevant operating procedures were updated to include the instructions for the Controllers on how to disable the system.

However, Network Intelligence team improved the NAP algorithms to accommodate network abnormal operating conditions. After the modified algorithms were successfully tested and implemented, it was recommended to retain the DVMS enabled under those operating conditions.

5.1.11. Develop a Switch to Change Operating Modes of DVMS

Initially, in order to switch the operating modes of DVMS (from $V_{99\%}$ to $V_{1\%}$ and vice versa), a Service Desk request was required to be raised and it would take a few days (minimum 1 day if escalated) to complete the task. While based on the funding agreement between UE and ARENA, DVMS needed to be switched from $V_{99\%}$ to $V_{1\%}$ in 10 minutes for demand response purposes.

Therefore, it was strongly recommended to modify SDVMA and NAP so that a switch could be developed in MOSAIC SCADA for the Controllers to switch the operating modes of DVMS in a prompt way. Therefore, all feasible options were discussed with the stakeholders to identify the least-cost technically acceptable one.

As a result, it was agreed that NAP sends two voltage recommendations for both modes of $V_{99\%}$ and $V_{1\%}$ to SDVMA simultaneously and based on the status of mode switch (defined by the Controller), the appropriate NAP voltage recommendation would be considered by SDVMA and sent out to the field VRR.

5.1.12. Retain the Emergency Voltage Set-Points in Final Solution

Since one of the business requirements for VRRs was to retain the functionalities of DRMMC-T3, it was recommended to retain the emergency voltage set-points (E1 & E2) in the final scheme. Therefore, if demand reduction is required while the DVMS is not available due to maintenance or loss of communication from NAP, the Controllers will be able to manage the demand on the network via reducing the voltage at zone substations.

5.2. Field Works

To implement the DVMS project, a technical scope of works was developed to upgrade (existing DR-T3 to new DR-E3) or install new (A. Eberle REG-D) VRR) at all zone substations (total 47) within the UE distribution network, and to configure the SCADA communications to achieve the DVMS functionality.

The below sections summarise the major issues which were identified and rectified/being rectified during the commissioning of the DVMS at different zone substations.

5.2.1. Loss of Ancillary Power Supply at Zone Substation

After conducting demand reduction test on North Brighton (NB) zone substation, both station normal and standby supply phase failure relays tripped due to selecting a low voltage set-point by the DVMS and the entire station service ancillary power supplies went off supply. The first action taken for investigation of this issue was to check the tap positions of the station services transformers and also the settings of the station normal and standby supply phase failure relays. As a result of this investigation, it was decided to tap up both station services transformers by one tap (2.5% = 6.25V) to increase the voltage level supplied to the station normal and standby supply phase failure relays. However, this action did not prevent the relays from tripping when the DVMS was operating in demand reduction mode. As a next step, the applied settings to the station normal and standby supply phase failure relays were tested and one of the relays was found faulty which was replaced with a new one. In order to ensure operating the DVMS in demand response mode would not cause any relays tripping, the below instructions were proposed to be followed:

- Place the analog switch for U_{max}[V] at 260V for both normal and standby phase failure relays;
- Adjust the analog switch for U_{min} [%U_{max}] in such a way that both normal and standby phase failure relays operate at 216V with a tolerance of ±0.5V; and
- The other settings of the relays shall be remained unchanged.

Figure 25 shows the normal and standby supply phase failure relays installed at NB zone substation.

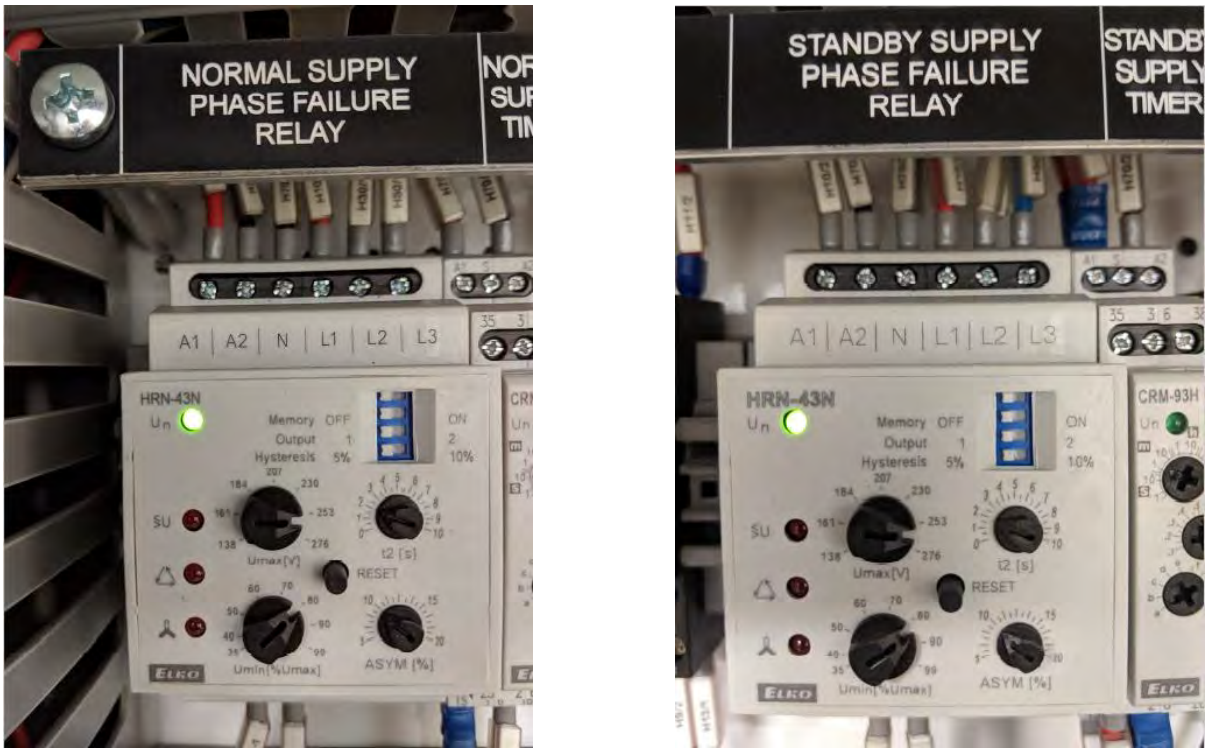


Figure 25 Normal and Standby Supply Phase Failure Relays at North Brighton (NB) Zone Substation

The proposed settings were successfully tested on the relays and since applying the new settings on the station normal and standby supply phase failure relays, operating the DVMS in demand reduction mode did not cause any issues for NB zone substation.

5.2.2. Discrepancies on Maximum Transformer Winding Temperature Readings

After upgrading the existing DRMCC-T3 with DR-E3 relays, it was noticed that some of the maximum transformer winding temperature readings for the zone substations did not match anymore and there was a high level of discrepancies between the values. Further investigation revealed that some default settings were applied to the DR-E3 units instead of site specific settings. Applying the transformer site specific settings solved this issue.

Figure 26 shows the readings for maximum oil and winding temperatures of two zone substation transformers prior to and post implementing the DVMS. As this figure shows, there were some discrepancies after upgrading the DR-E3 relays. All of the identified reading discrepancies were resolved.

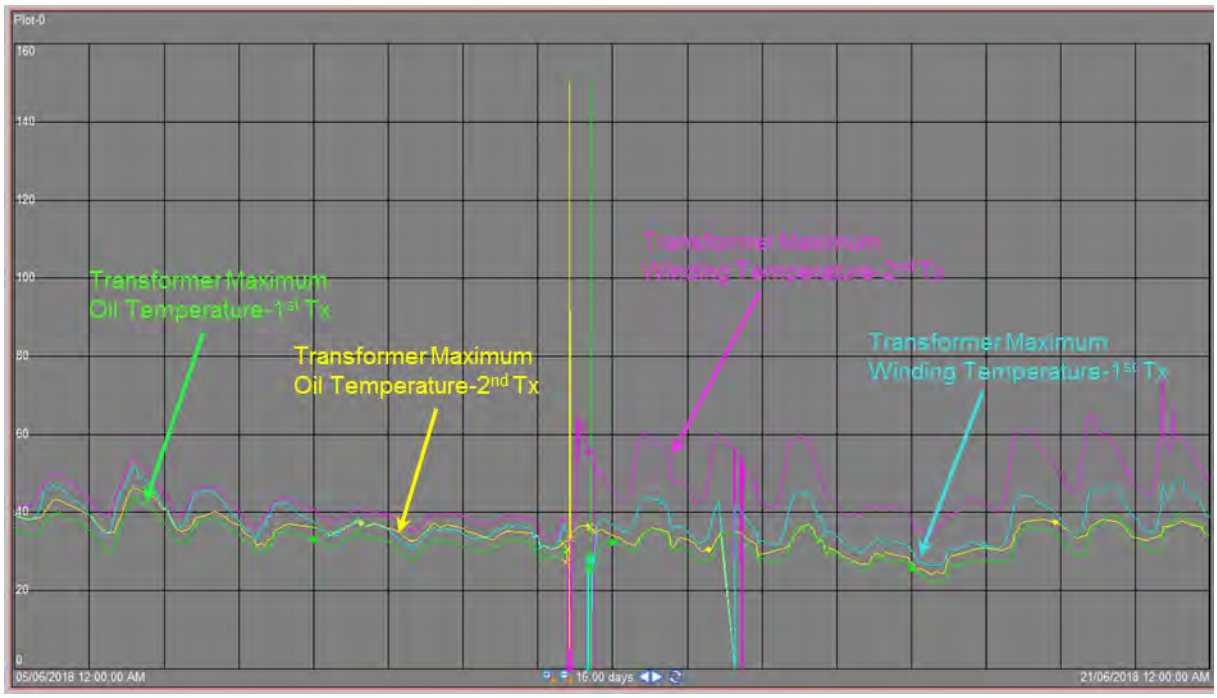


Figure 26 Readings for Maximum Oil and Winding Temperatures of Two Zone Substation Transformers Prior to and Post Implementing the DVMS

The investigation outcomes on readings of maximum oil and winding temperatures for some other zone substation transformers are given in Milestone #7 Report.

5.2.3. Excessive Number of Tap Changes Performed by Zone Substation Transformers

It was noticed that the number of tap changes for some zone substations increased after commissioning the new relays under the DVMS rollout. After analysing the data, it was found that the number of tap changes did not match the recommendations from the NAP which were generated to change the voltage set-points. Therefore, the field investigation commenced and it was revealed that this issue was on the contaminated OLTCs contactors for the zone substations at which the VRRs had been replaced with A. Eberle REG-D units.

Some of these zone substations also received a large number of OLTC master control failed alarms. After analysing the relay logs, it was concluded that there was no general design issue and most likely the root cause of this issue would be the contaminated contacts of the tap changers. The initial plan was to clean the contacts of the OLTCs and monitor the results over a couple of weeks. This solution improved the situation and no or few number of OLTC master control failed alarms received after completing the maintenance. However, after a few weeks these alarms were raised again and also the number of tap changes were increased significantly.

Whilst the root cause could be traced to dirty wiper contacts at the OLTC to position resistance chain, it was noted that prior to installing A. Eberle REG-D relays, in many of the old VRR arrangements, a TPT-194 transducer was used to convert tap position resistance into 4-20mA used by the OLTC RTU[12].

One option of the TPT-194 was a 3-wire connection to the tap position resistor chain that had been the connection arrangement previously used at the question zone substations. This was in contrast to the recommended A. Eberle REG-D connection, where all possible connections only used two of the three terminals at the resistance chain.

[12] RTU = Remote Terminal Unit.

Another potential issue with the A. Eberle REG-D relay was that the output voltage was limited to 10V maximum, whereas the TPT-194 output voltage was 20V maximum or 50V maximum (depending on option chosen).

Therefore, it was proposed to trial the 3-wire connection of the TPT-194 at Sandringham (SR) zone substation in order to prove that this arrangement would give resultant measured voltage which was largely unaffected by the presence of wiper contact resistance. This transducer is shown in Figure 27.

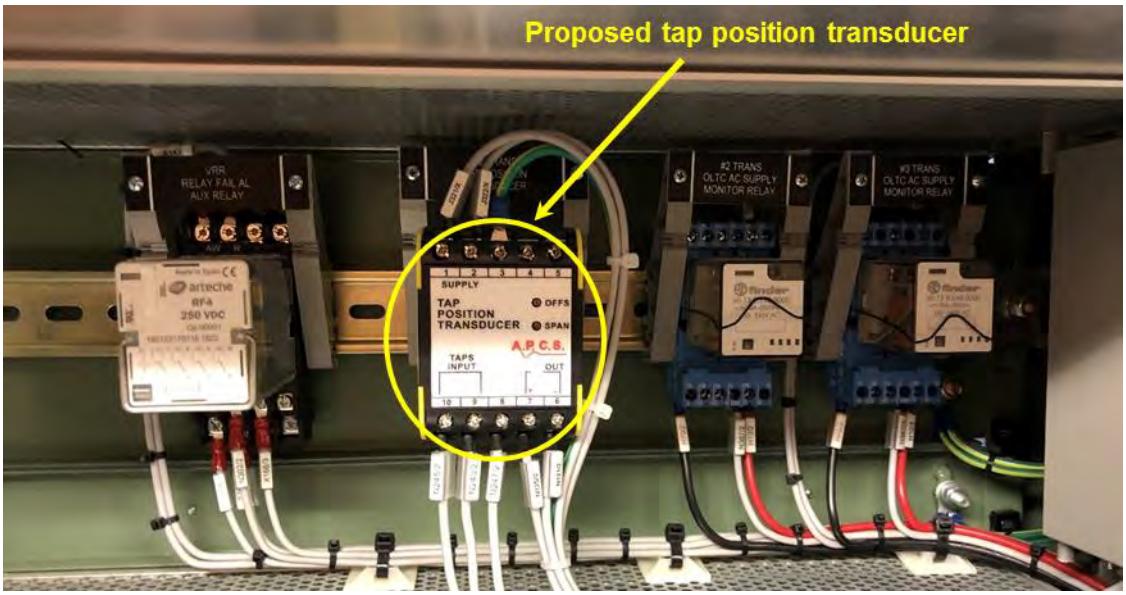


Figure 27 Tap Position Transducer Proposed for Zone Substation with A. Eberle REG-D Voltage-Regulating Relays Installed

After trialling this arrangement, it was observed that the issues at SR zone substation were resolved. As a result, it was planned to implement this arrangement on the zone substations that experienced excessive number of tap changes and also OLTC master control failed alarms.

Therefore, the following works were proposed to address these issues:

- Upgrade the transformer tap position circuit via a transducer upgrade on the power transformers across the zone substations managed by the A. Eberle REG-D VRRs.
- The transducer needs to be A.P.C.S. type with the exact model to be selected by Service Provider as part of detailed design. Where a different transducer type is required, the Service Provider shall propose an alternative and seek endorsement from UE prior to proceeding with procurement and finalisation of the design. The upgraded tap position indicator (TPI) circuit shall be immune from electrical noise and not be susceptible to indicating incorrect/spurious/phantom/erroneous tap positions.

By completing the above works, the numerous 'phantom' OLTC operations which in turn flooded the Network Control Centre with 'out of step' and 'master control fail' alarms as well as driving unnecessary tap changes on the parallel transformers were mitigated. These issues were generating costly fault callouts, more frequent maintenance of OLTC equipment as well as potentially limiting our ability to participate in the RERT events.

5.2.4. Zone Substation Transformer OLTC Low-Tension Supply Isolation

As part of the DVMS rollout project, majority of the zone substations which had utilised legacy MD3311 OLTC RTU for low-tension bus voltage regulation were upgraded to a voltage regulation scheme based on A. Eberle REG-D relays.

In the previous MD3311-based voltage regulation scheme, an OLTC isolation switch was provided on the OLTC control panel in the control room for each transformer for the purposes of isolating the 400VAC and 230VAC supply into the OLTC mechanism box. The tap-change-in-progress (TCIP) contact in the OLTC mechanism box was wetted with AC supply. The OLTC isolation switch allowed the OLTC mechanism box to be safely isolated for maintenance works. The tap position resistor circuit was supplied at 20VDC or 50VDC (depending on the zone substation) and

it was not isolated by the OLTC isolation switch. Figure 28 shows the OLTC isolation switches which were used by the legacy MD3311 OLTC RTUs.

Figure 28 OLTC Isolation Switches Utilised by Legacy MD3311 OLTC RTUs

In the new A. Eberle REG-D-based voltage regulation scheme, an OLTC isolation switch is no longer provided. However, all 400VAC and 230VAC supply in the OLTC mechanism box can still be isolated via dedicated miniature circuit breakers (MCBs) either in the VRR cubicle or at the main 400VAC board. The TCIP contact is now wetted by the 110V or 240V station DC supply.

For safe isolation of the OLTC mechanism box, the agreed interim solution was to switch off the 110V/240 VDC MCB supplying the A. Eberle REG-D relay, which would also remove the DC wetting supply on the TCIP contact. Until the permanent solution is implemented, this interim procedure will be followed.

A consequence of switching off the supply to the A. Eberle relay was that other A. Eberle relays in the zone substation would switch from automatic to manual voltage regulation mode as they would see the A. Eberle REG-D relay was no longer communicating (i.e. ELAN error). This means that UE NCC would have to perform manual voltage control for other transformers still in service whilst maintenance was being carried out on one transformer.

This issue as well the ones described in Section 5.2.3 were costly to manage and could introduce risk of transformer failure as alarms and operations were less reliable and may be ignored. Therefore, UE proposed to arrest these issues as far as reasonably practicable (AFAP) to ensure UE meets its regulatory obligations in the best interest of the business and customers. Therefore, the below works were proposed for implementation:

- Installation of dedicated MCBs to provide a practical and safe means of VRR OLTC equipment DC circuit isolation issue for the impacted power transformer:
    - MCBs shall be selected for DC voltage and suitably rated for the application.
    - MCBs shall be graded with upstream circuit protection (either MCB or fuse).
    - For applications with the A. Eberle REG-D VRR, the MCB shall be located within the protection panel in the zone substation control room.
    - For applications with the Dynamic Ratings DR-E3 VRR (where required), the MCB shall be located within the protection cubicle mounted on the transformer.
    - Alternative locations for the new MCB may be required on a case by case basis but shall be discussed as part of the single-line diagram (SID) process and COM[13] review so as to ensure the intended requirements are met and all stakeholders are satisfied.
- Installation of dedicated panel mounted 'CB maintenance' switches to provide a simple and safe means for fitters and operators to isolate the circuit breaker status changes from the VRR scheme during circuit breaker maintenance. These switches are required at all zone substations on transformer incomer and bus-tie circuit breakers:
    - Switches shall be suitably rated for the application.
    - The switch shall be Santon type with the exact model to be selected by Service Provider as part of the detailed design process. Where a different switch type is proposed, the Service Provider shall seek endorsement from UE prior to proceeding with procurement and finalisation of the design.
    - For applications with the A. Eberle REG-D VRR, the switches shall be located on the protection panel in the zone substation control room.
    - For applications with the Dynamic Ratings DR-E3 VRR (where required), the switches shall be located within the protection cubicle mounted on the transformer.
    - Alternative locations for the new switches may be identified or deem more suitable on a case by case basis but shall be discussed as part of the SID process and COM review so as to ensure the intended requirements are met and all stakeholders are satisfied.
    - The status of these new switches shall not be provided to the NCC via SCADA.
    - Each new switch shall be labelled 'XXX CB Maintenance' where XXX shall be the circuit breaker designation, for example '#1 TR 22kV', '1-2 22kV BT', etc.
- A training package shall be developed by the Service Provider and presented to UE's incumbent faults/maintenance contractor such that fitters, operators, testers and other personnel understand the purpose and correct operation of the new MCBs and switches. Any relevant field procedures shall be updated.
- A similar awareness package shall be developed by the Service Provider and presented to UE's NCC and Asset Management staff.

The proposed MCB for OLTC isolation switch is shown in Figure 29.

[13] COM = Constructability, Operability & Maintainability.

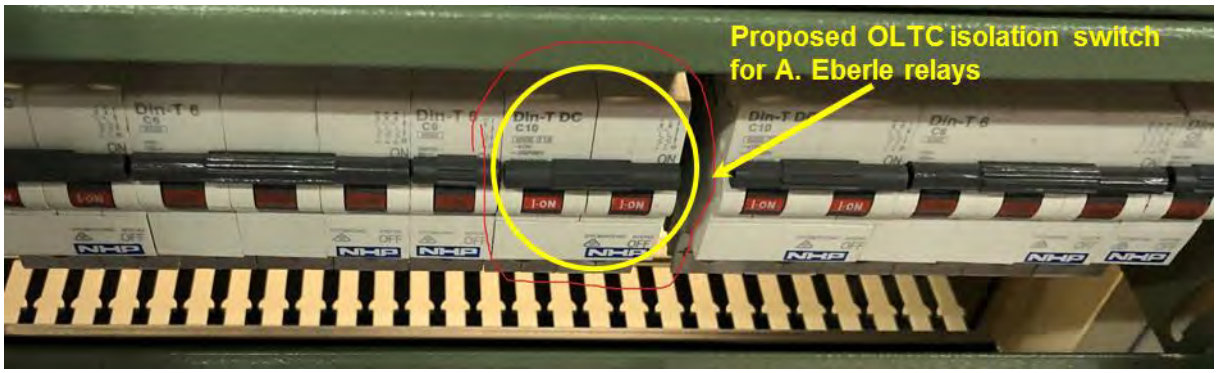


Figure 29 Miniature Circuit breaker Used as an OLTC Isolation Switch

5.2.5. Voltage Hunting due to Settings of Circulating Current Operating Mode

Further investigation on the excessive number of zone substation transformer tap changes revealed that the inverse time curve applied to the A. Eberle REG-D relays using circulating current mode was not well-suited (too fast) as shown in Figure 30.

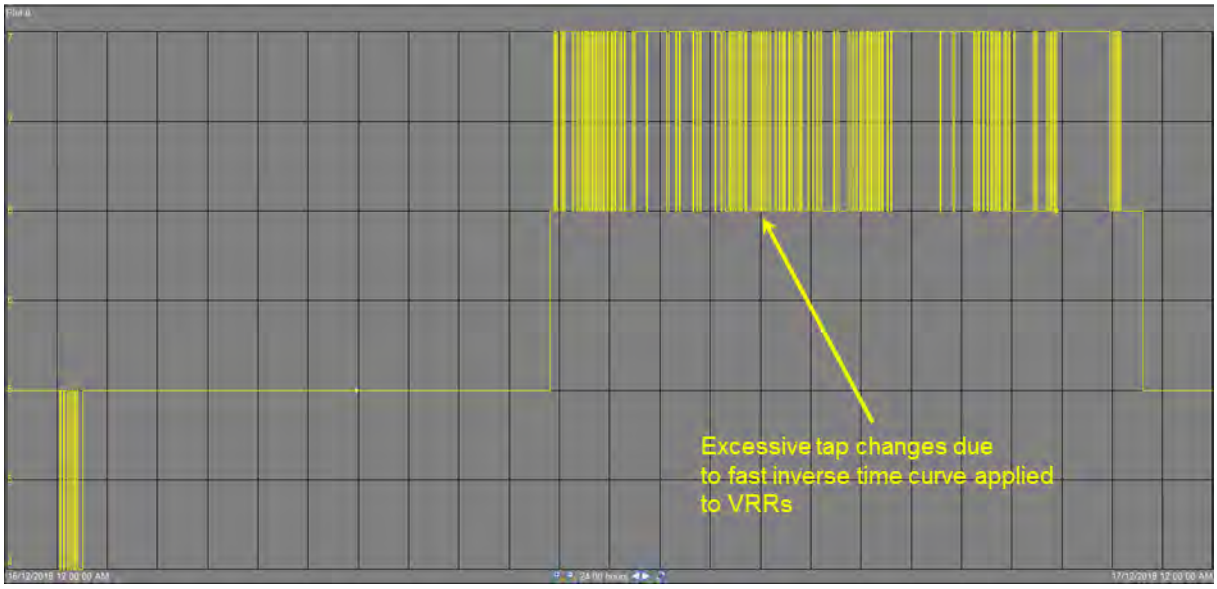


Figure 30 Excessive Number of Tap Changes due to Fast Inverse Time Curve of Circulating Current Operating Mode of Voltage Regulating Relays

After preliminary investigation, the project team decided to trial a slower curve at four zone substations. The trial outcomes confirmed reducing the frequency of tap changes as shown in Figure 31.

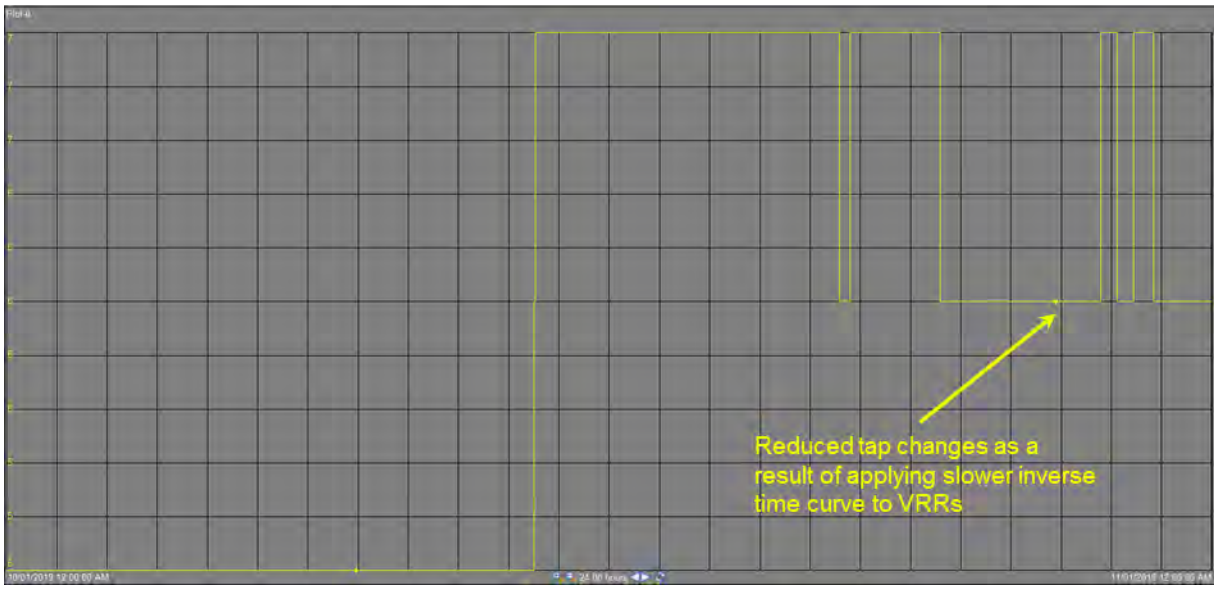


Figure 31 Reduced Number of Tap Changes Post Applying Slower Inverse Time Curve onto Voltage Regulating Relays Operating in Circulating Current Mode

Therefore, the new slow curve was implemented onto additional zone substations that were using circulating current mode.

5.2.6. Send Recommendations to Each VRR

DVMS initially sent the NAP voltage recommendations to the Master relays only. Based on the conducted tests once the bus-tie circuit breaker was opened, the Follower transformer started changing the tap and created some circulating currents between the transformers and resulted in detrimental impacts. The reason for this behaviour was during normal operating conditions, the Follower VRRs followed the Master VRR and changed the transformer taps but the actual set-points in the Follower relays were not changed as the Follower VRRs did not receive the NAP voltage recommendations.

Then, when the Follower VRRs were switched to Independent mode as a result of opening the bus-tie circuit breaker, they reverted back to the set-point they had been at before running in Master-Follower that was different from the current voltage set-point of the Master VRR.

It was then confirmed with Dynamic Ratings that it would be feasible to send the NAP voltage recommendations to all of the relays including the Followers at zone substations without any modifications on the current firmware. This improved the performance of DVMS especially when a bus-tie circuit breaker was open by the Controller.

By sending NAP voltage recommendations to each relays, the Master VRR will consider the control command and act accordingly while the Follower relays will only change the voltage set-points internally but at the same time follow the Master VRR.

5.3. Financial Assessment

This section of the report summarises the evaluation of the impact of dynamic voltage regulation on the lifetime of zone substation transformer OLTCs. In order to conduct this evaluation, the numbers of tap operations prior to (CY2017) and post (CY2019) implementation of the DVMS technology are taken into consideration.

Table 12 summarises the average daily number of tap operations for different zone substations in the 2017 and 2019 calendar years. The average daily numbers of tap operations for different months of these two years are given in Milestone #7 Report.

Table 12: Average daily number of zone substation transformer tap changes prior to and post implementing the DVMS

Item	CY2017	CY2019	Change Rate
Average	12	16	32%

According to Table 12, operation of the DVMS has resulted in additional tap operations by an average of 32%. This is mainly due to the impact of solar PV systems during day times at which the DVMS needs to change the voltage set-points at zone substations.

In order to calculate the maintenance costs associated with additional number of tap changes due to the DVMS operation, the below assumptions are taken into consideration. It should be noted that, the below assessment is a high-level analysis and more detailed investigations need to be conducted to estimate the cost associated with the DVMS operation.

- Average number of tap changes for a zone substation transformer (without DVMS in service):

  25,000 per 4 years = > 6,250 (25,000/4) per year = > 17 (6,250/365) per day.

- Service cost associated with OLTC operation:

  $20,000 per 4 years = > $5,000 ($20,000/4) per year = > $14 ($5,000/365) per day.

- Maintenance cost for each tap operation:

  $0.80 ($14/17).

- Cost to replace a zone substation transformer[14]:

  $2.2m.

- Total number of tap changes for a zone substation transformer over its lifetime (without DVMS in service):

  500,000.

- Number of services for a zone substation transformer over its lifetime:

  20 (500,000/25,000).

- Cost of each tap operation for a zone substation transformer over its lifetime:

  $4.40 ($2.2m/500,000).

- Total cost estimated for each additional tap operation:

  $5.20 ($0.80+$4.40).

Table 13 summarises the financial impact of the DVMS technology on zone substation transformers.

Table 13: Estimated financial impact of DVMS operation on zone substation transformers

Item	CY2017	CY2019	Estimated Additional Cost
TOTAL	199,655	275,210	$309,374

According to Table 13, an additional annual cost of $310k is estimated due to the operation of the DVMS scheme. It should be noted that a number of factors contribute to this additional cost such as the age and type of OLTCs. For example, the associated tap operation cost for a transformer built in 1960 will be higher than that for a 2020 built transformer.

[14] NPV is not considered here.

5.4. Identification of distribution substations for low voltage remedial works

Milestone #2 Report identified that during days of extreme heat when the demand was high, the voltage profiles at some zone substations could coincidentally exceed both the upper and lower regulatory voltage limits even when DVMS was active in Enabled-Auto $V_{99\%}$ (normal) mode.

Under this condition, the algorithms deployed in the NAP optimised to minimise the number of customers experiencing over and under-voltages by equalising the number of customers over and the number of customers under. This means there was no opportunity, when this condition arose, to undertake demand response without going beyond the regulatory voltage limits.

When the condition occurred, it was not a widespread issues across all parts of the network. Rather it tended to be localised issues triggered by parts of the LV network that have

a) distribution tap settings set sub-optimally (~6% of distribution substations);
b) circuits with high phase unbalance (~5% of low voltage circuits); and/or
c) excessively long LV circuits or loaded assets (less than 1% of low voltage circuits).

Part of the ARENA funding provided to UE was used to address these localised issues and tighten up outlier site voltage profiles to provide sufficient voltage margins within the regulatory voltage limits to deliver the required demand response capability.

In order to reduce the voltage spread of the zone substation during peak demand periods and consequently, ensure $V_{1\%}$ (demand response) mode could be operated effectively to provide a demand response, LV network remedial works were undertaken during 2018 to deliver the contracted 30MW of demand response for summer 2018/19.

Figure 32 demonstrates how the low-voltage remedial works improves the voltage profile of a zone substation and provide higher opportunity for demand reduction under high demand conditions.

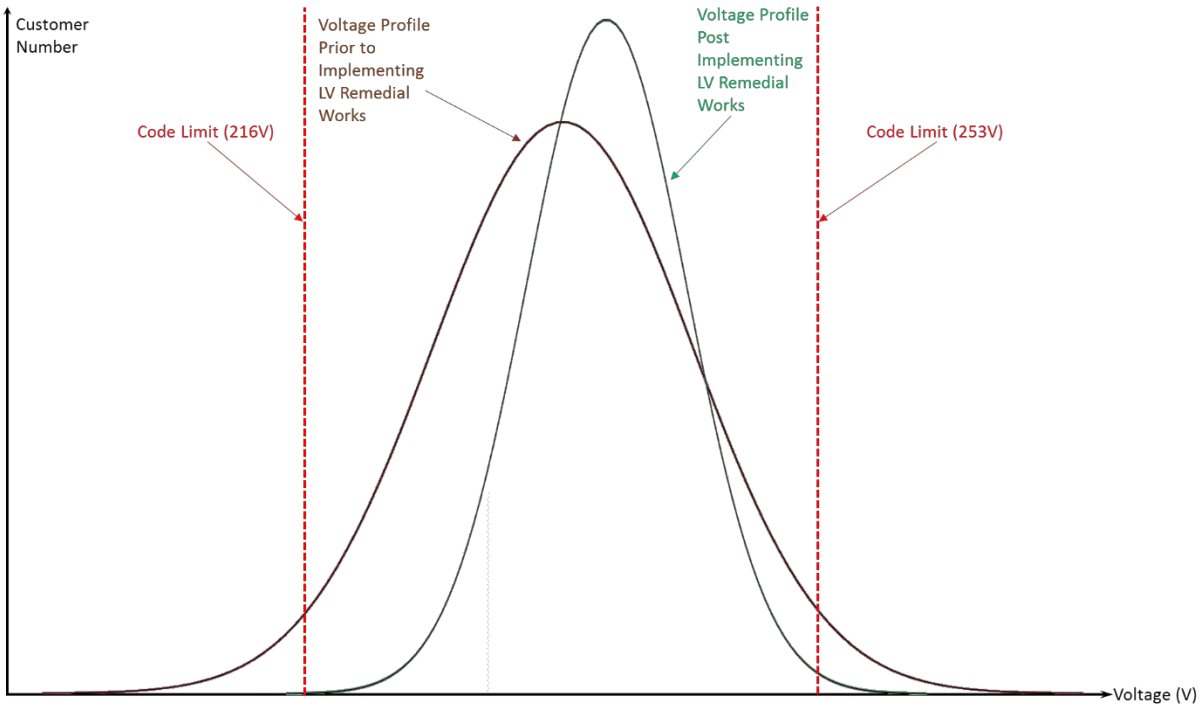


Figure 32 Estimated Impact of Low-Voltage Remedial Works on Zone Substation Voltage Profile

UE developed an algorithm that was used to optimally identify the minimum number sites required for LV remediation to achieve voltage compliance with a 3% voltage margin reserved for demand response at times of peak demand.

In order to implement the LV remedial works, a holistic programme was put in place to identify the distribution substations, which when reducing their voltage spreads, would have the maximum improvement on the voltage spread profile of the entire zone substation for which DVMS was applied. The flowchart shown in Figure 33 was deployed to identify these distribution substations.

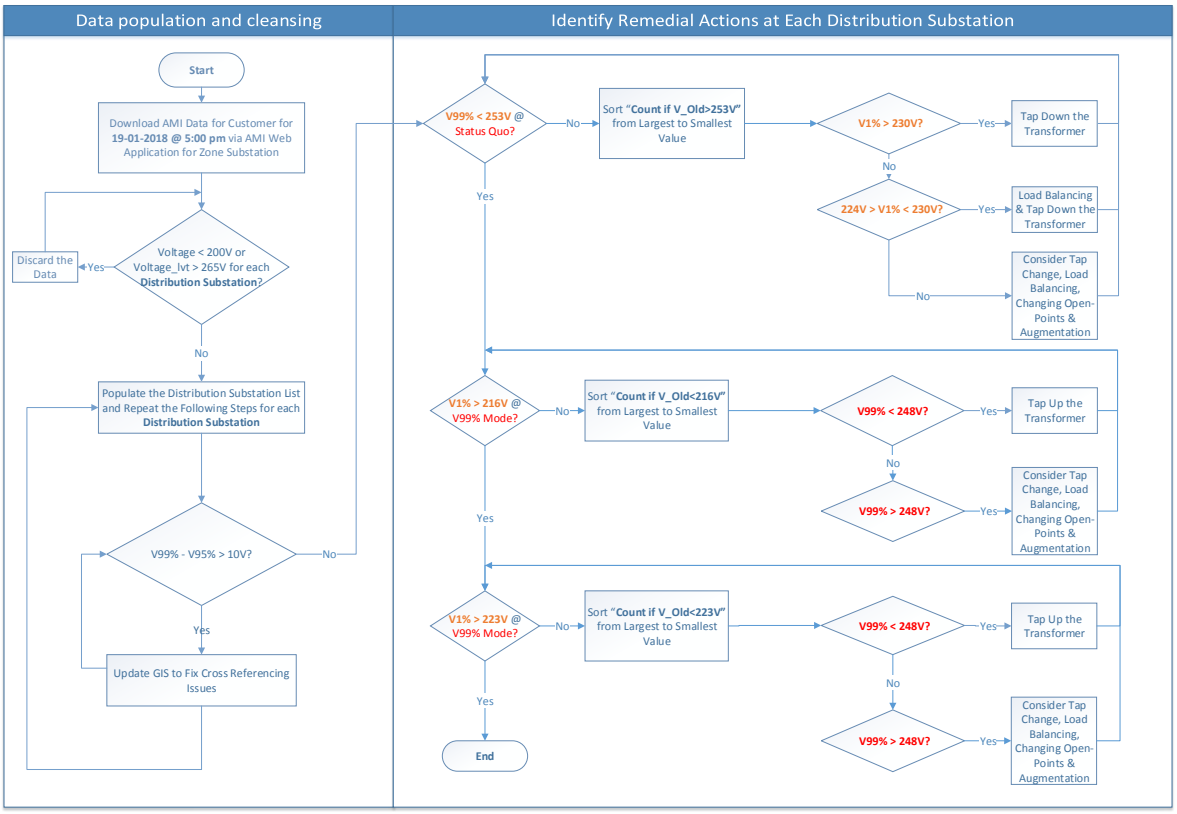


Figure 33 Algorithm Deployed to Identify Distribution Substations for Low-Voltage Remedial Works

This algorithm took the below scenarios into consideration to ensure the appropriate remedial actions were taken on the identified distribution substations:

- Status quo (DVMS is not operational); and
- DVMS is operating in $V_{99\%}$ (normal) mode.

This algorithm also explained the appropriate remedial actions required for the identified distribution substations. The corrective works on the LV network were categorised into the below groups:

- Adjusting the tap settings of distribution transformers;
- Balancing the load along the LV circuits;
- Checking and correcting the loose connections;
- Investigating and relocating the LV open points; and
- Augmenting the constrained distribution substations and LV circuits (only if required).

According to this flowchart, AMI (smart-meter) data for all of the customers supplied by a zone substation was populated into the model. The populated data included the voltage delivered to each customer at the peak demand time for the UE distribution network.

To ensure the data considered for identifying the non-compliant distribution substations did not include the data associated with outages, brownouts or network switching activities, any values above 265V and below 200V were discarded.

As the next step, the $V_{1\%}$ and $V_{99\%}$ values for each distribution substation were calculated. If the difference between $V_{1\%}$ and $V_{99\%}$ was higher than 10V then, the potential discrepancies between the network connections recorded in

Geographical Information System (GIS) and the connections in the field were investigated and the customers who had been supplied by adjacent transformers but were incorrectly recorded in GIS were identified. The connections for the identified customers were then corrected in GIS to prevent any inappropriate decisions being made by DVMS. This step was effectively a data cleansing exercise to ensure the customer connection data is mapped to the correct distribution substation.

For more information on this algorithm, refer to Milestone #3 Report.

6. Achievements

DVMS and smart-meter technology provides distributors the opportunity to achieve the following outcomes:

- Deliver demand response services for RERT using voltage reduction to increase supply-demand reserve levels in the NEM to help avoid load shedding;
- Deliver step-change improvements in steady-state voltage compliance by dynamically adjusting voltages at zone substations using customer voltage feedback from smart meters in response to changing load and generation patterns on the network; and
- Allow for higher penetrations of customer solar PV systems to be connected to the network (and at increased export levels) without adverse impacts on network performance (i.e. increased solar hosting capacity), while reducing customer voltage complaints.

UE through this ARENA-funded project, has been able to demonstrate the benefits and share the learnings of this technology with the broader industry.

6.1. Benefit of DVMS on Customer Voltages

With the DVMS technology fully rolled-out across the UE electricity distribution network and in operation now for more than a year, UE has been able to monitor and demonstrate the positive impact DVMS has had on customer steady-state voltages. This section shares the learnings of this investigation.

DVMS has been developed with the intent of facilitating steady-state voltage compliance against AS61000.3.100. This Australian Standard allows for customer steady-stage voltages to exceed 230V + 10% (253V) or fall below 230V - 6% (216V) for no more than 1% of the time.

DVMS helps to achieve this compliance at a population scale by selecting an appropriate voltage set-point at each zone substation that facilitates at least 99% of our customers at any instant in time remaining within the 253/216V limits, with the view that residual outliers could be addressed on a site-by-site basis with localised remedial actions. This approach allows UE to strike an appropriate balance between population-based voltage regulation versus individual site-based remedial actions, while maximising the level of demand response provided for RERT. Outliers are likely to be sites that have a localised issue such as loose connections (for under-voltage) or large export of solar PV generation through long service lines (for over-voltage) and these are best suited to a localised remedial action. As such the two operating modes for DVMS ensure that for normal operation no more than 1% of customers operate above 253V and for demand response mode, no more than 1% of customers operate below 216V.

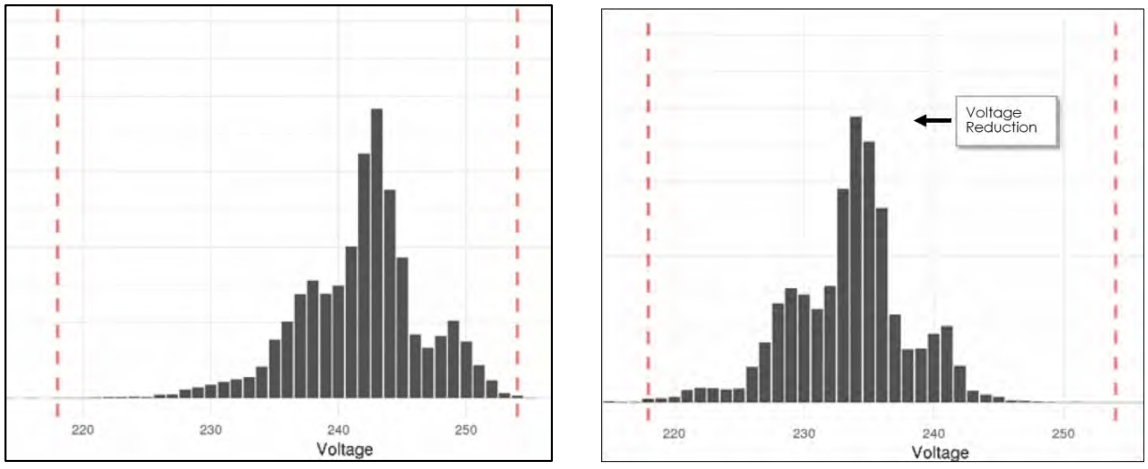


Figure 34 DVMS Operating Modes to Maximise both Demand Response and Voltage Compliance

A daily report has been produced on the performance of DVMS for each zone substation across the UE network documenting the results of the previous day. The report includes the:-

- percentage of customers experiencing steady-state voltages less than 216V (i.e. 230V – 6%);
- percentage of customers experiencing steady-state voltages greater than 253V (i.e. 230V + 10%);
- percentage of customers within the range 216V to 253V (i.e. 230V + 10% / – 6%);

- actual $V_{1\%}$ and $V_{99\%}$ voltages relative to the AS61000.100.3 limits of 216V and 253V respectively; and
- average zone substation transformer tap position compared to the available tap range.

In summary, with DVMS in service:-

- $V_{99\%}$ voltage is being regulated at all sites within the 253V limit;
- $V_{1\%}$ voltage is being regulated at all sites within the 216V limit;
- 0.005% of customers are at times operating below 216V and 0.31% of customers above 253V; and
- $V_{1\%}$ is 231V and $V_{99\%}$ is 251V, a spread of 20V and a demand response margin down to 216V of 15V.

The voltage spread for each zone substation is consistent with the type of area being supplied. HGS (Hastings) zone substation for example supplies a semi-rural area and has a wider voltage spread than an urban industrial area such as HT (Heatherton). The margin between $V_{1\%}$ and 216V is an opportunity for demand response using voltage reduction.

The discrete nature of the voltage set-point recommendations available to DVMS means that levels fluctuate on a day-by-day basis across different zone substations between 0% and 1%, with an average of 0.31% for over-voltages. Overall, the performance remains consistent across the population on typical mild days.

UE calculated voltage spread as the difference between the 99th percentile value and the 1st percentile value. As part of this project, UE undertook a large number localised remedial works on its LV distribution network to tighten up the voltage spread and maximise the opportunity for achieving coincident voltage compliance and demand response capability. These works involved tap changes on distribution transformers, rectification of loose connections, phase balancing and transferring customers across low-voltage open points. Figure 35 demonstrates the average values of voltage spread for each UE's zone substation prior to and post implementation of the LV remedial works.

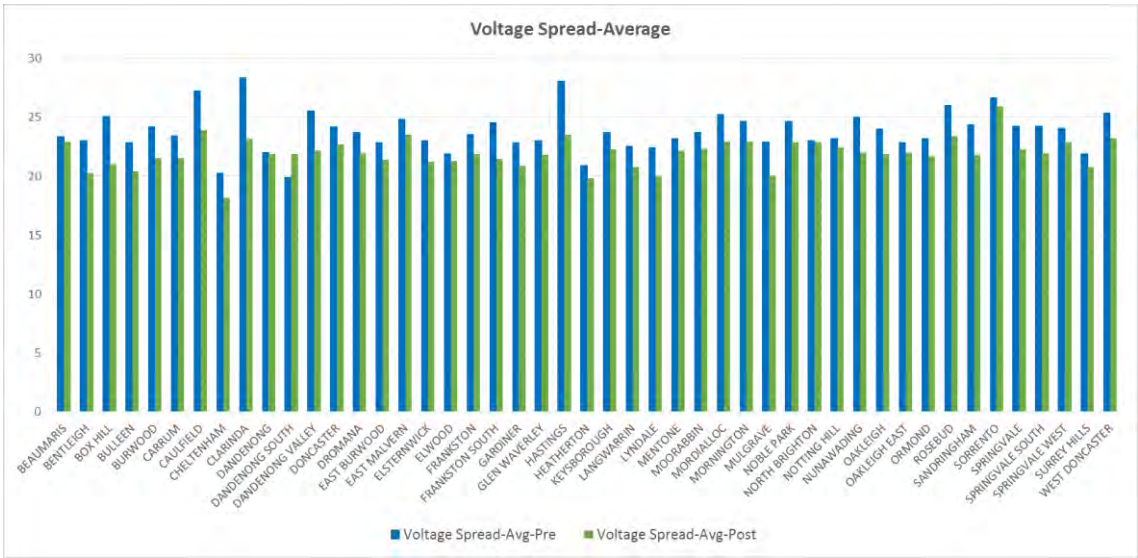


Figure 35 Average Voltage Spread (V) on each Zone Substation Pre and Post LV Remedial Works

As per Figure 35, LV remedial works under the DVMS rollout project have reduced the voltage spread at all zone substations and consequently, increased the level of demand response capacity for RERT services. The remedial works undertaken have provided an additional 1% voltage reduction margin for demand response across the network.

6.2. Testing Demand Response Reserve Capability

UE undertook the demand response test with AEMO in late May 2020. The objectives of the tests were to i) confirm UE's demand response reserve capability achieves the required 30MW for RERT, and ii) ensure the ITT (Invitation to Tender) and activation communication channels were operating correctly and acted on within the required period of time of 30 minutes and 10 minutes, respectively.

AEMO called for an eighth test with UE on 26th May 2020 for a 2-hour period starting 13:00 market time for a capability of 30MW. Figure 36 shows the high-frequency sampling rate measurements of the total demand included

in UE's demand response portfolio, before, during and after the test. In Figure 36 activation status of the demand response mode in DVMS is shown in blue.

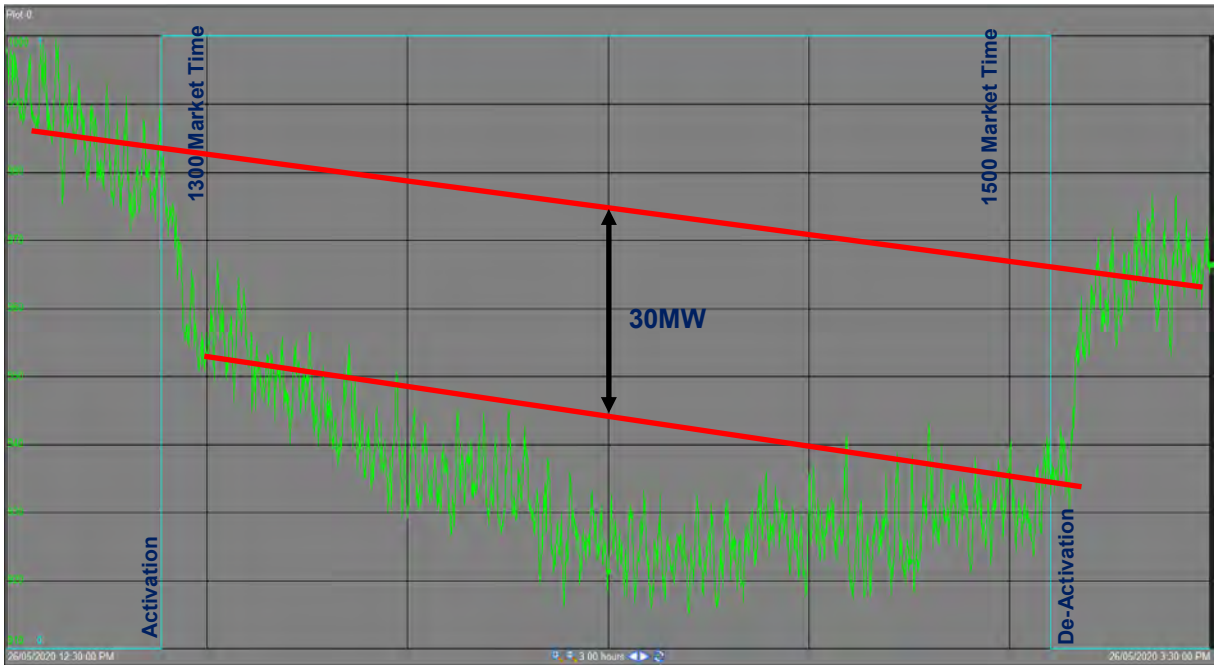


Figure 36 Test on 26th May 2020 Showing Demand Response due to Voltage Reduction (3-Hour Window)

Activation of the demand response by way of voltage reduction is evident in the minutes before the event start date (1300 market time) with demand falling from 985MW at 1248 to around 955MW at 1300. Therefore, the coincident time demand reduction achieved in the first interval is 985MW – 955MW = 30MW. Subsequent intervals also achieved demand reductions of at least 30MW.

Deactivating the demand response was undertaken by restoring network voltages which occurred from 1500 market time with demand rising from 935MW at 1500 to around 965MW at 1510. Therefore, the coincident time demand reduction in the final period is 965MW – 935MW = 30MW.

In summary, high-speed SCADA measurements (presented above) provide evidence that UE delivered at least the required 30MW of demand response capability for all half-hour periods and that the communication process to receive and accept the ITT, and the subsequent activation of the demand response reserve capability have been successfully demonstrated.

Figure 37 illustrates the relativity of the demand response performance to the total demand levels on the UE network during the entire day on which the test was conducted.

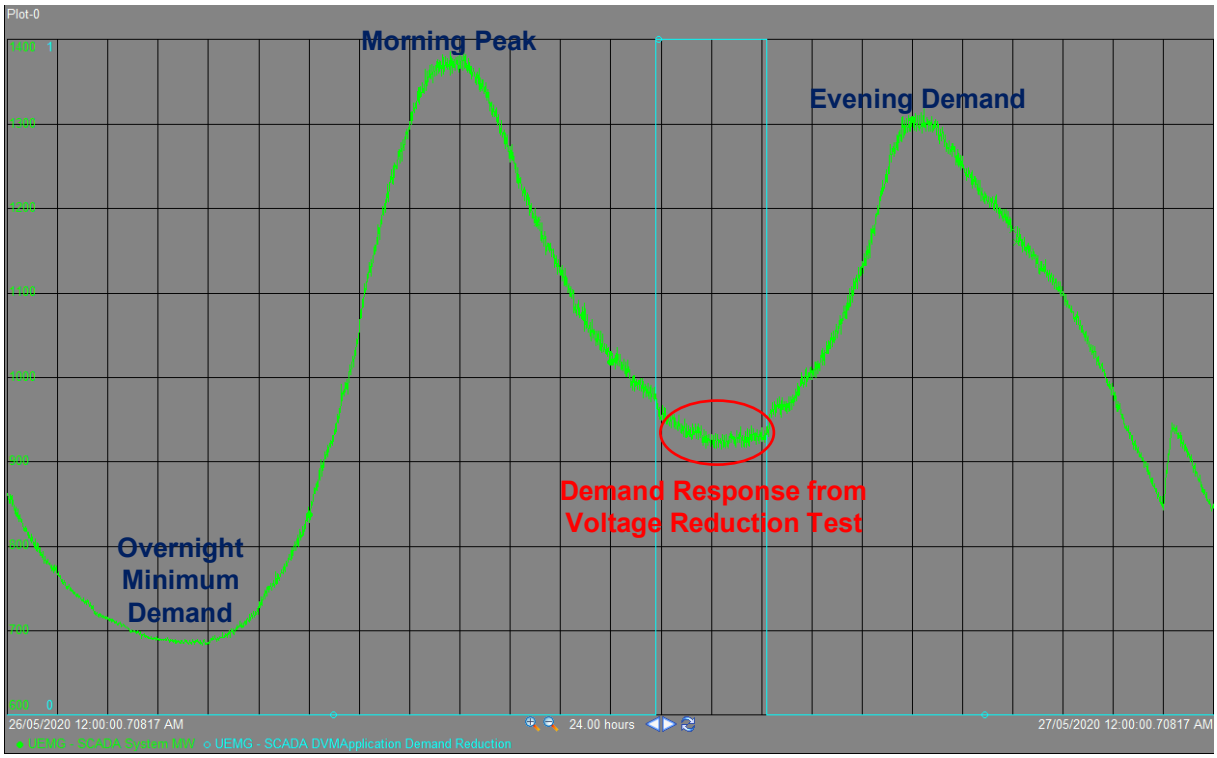


Figure 37 Test on 26th May 2020 Showing Demand Response due to Voltage Reduction (24-Hour Window)

6.3. Delivery of RERT Services

UE delivered RERT services for AEMO on two occasions during summer 2018/19:-

1. 30 to 42MW delivered on 24th January 2019 for 4 hours; and
2. 30 to 42MW delivered on 25th January 2019 for 4.5 hours.

6.3.1. First RERT Activation – 24th January 2019

AEMO called a live RERT activation with UE on 24th January 2018 for a 4-hour period starting 1700 market time for a capability of 30MW. The UE service area demand at the time was 1930MW, significantly greater than the demand at the time of the test period events. At this level of demand, the demand response could potentially be much larger than the demand response delivered during the testing at light load however, the key constraint in the magnitude of the demand response delivered shifts from available tapping range to the customers' voltage distribution spread. UE was able to achieve up to 42MW of demand response that day. Figure 38 shows the activation which occurred on the 24th using high-frequency SCADA metering of the UE service area demand. Activation status of the demand response mode in DVMS is shown in blue and is triggered 10-minutes before 1700 market time when we received instruction from AEMO to dispatch (noting that the timestamp on the chart below is in Melbourne local daylight savings time).

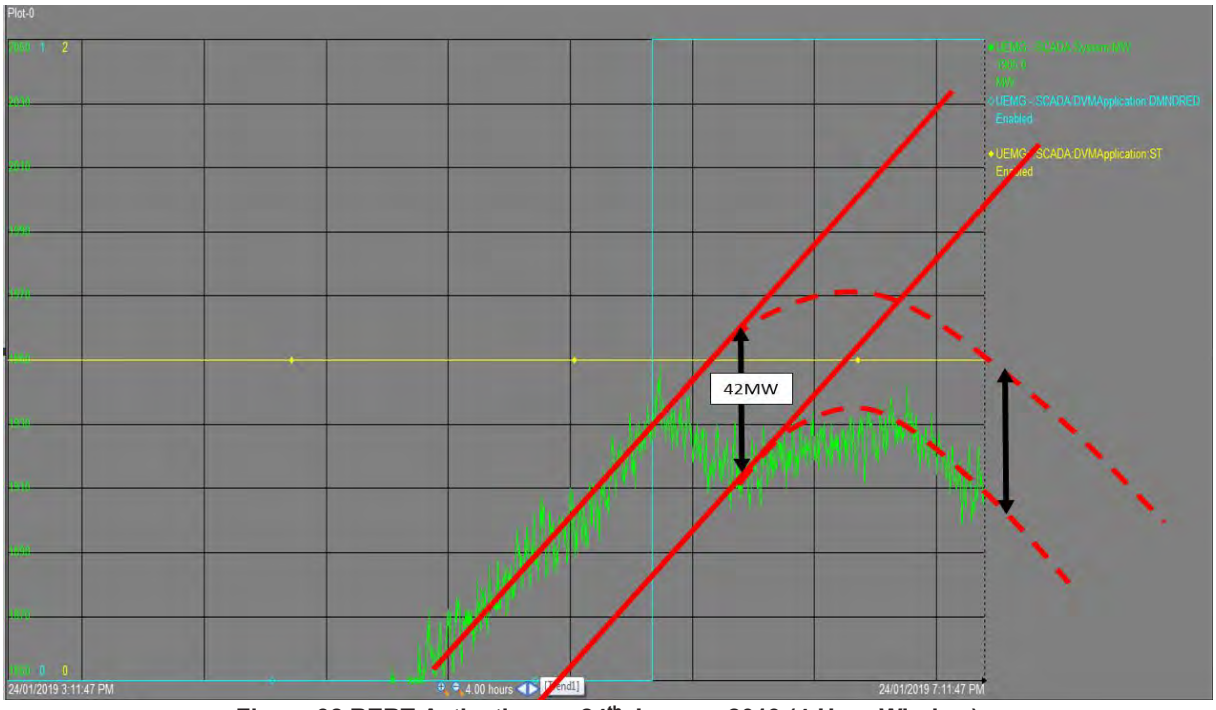


Figure 38 RERT Activation on 24th January 2019 (4-Hour Window)

The tapping of our zone substation transformers starts about 1 minute later, with the voltage reduction arresting the increasing demand (shown in green) at the time, forcing it to decline until further tapping down is inhibited by DVMS - which is designed to minimise the number of customers on the lower end of the voltage distribution at each zone substation receiving voltages outside of allowable voltage limits – i.e. maintaining compliance with AS 61000.3.100. Following completion of all tap downs across the fleet of zone substations, the aggregated UE demand then begins to rise on its original rate of change (solid red lines), albeit from a point 42MW lower than what it would have otherwise been.

The UE demand peaked that day just prior to activation, but would have normally peaked about 1 hour later. This is illustrated with the rate of change in demand increase slowing to the point it starts to decline as the evening arrives (dashed red lines).

Figure 39 illustrates how the demand response performance was observed throughout the duration of the 4-hour RERT period. Being a long dispatch period, the known thermostat effects of voltage reduction on demand (as discussed in Milestone #3 Report) contributed to a decline in the delivered demand response throughout the duration of the dispatch with the lowest demand response of 30MW delivered at the end of the period.

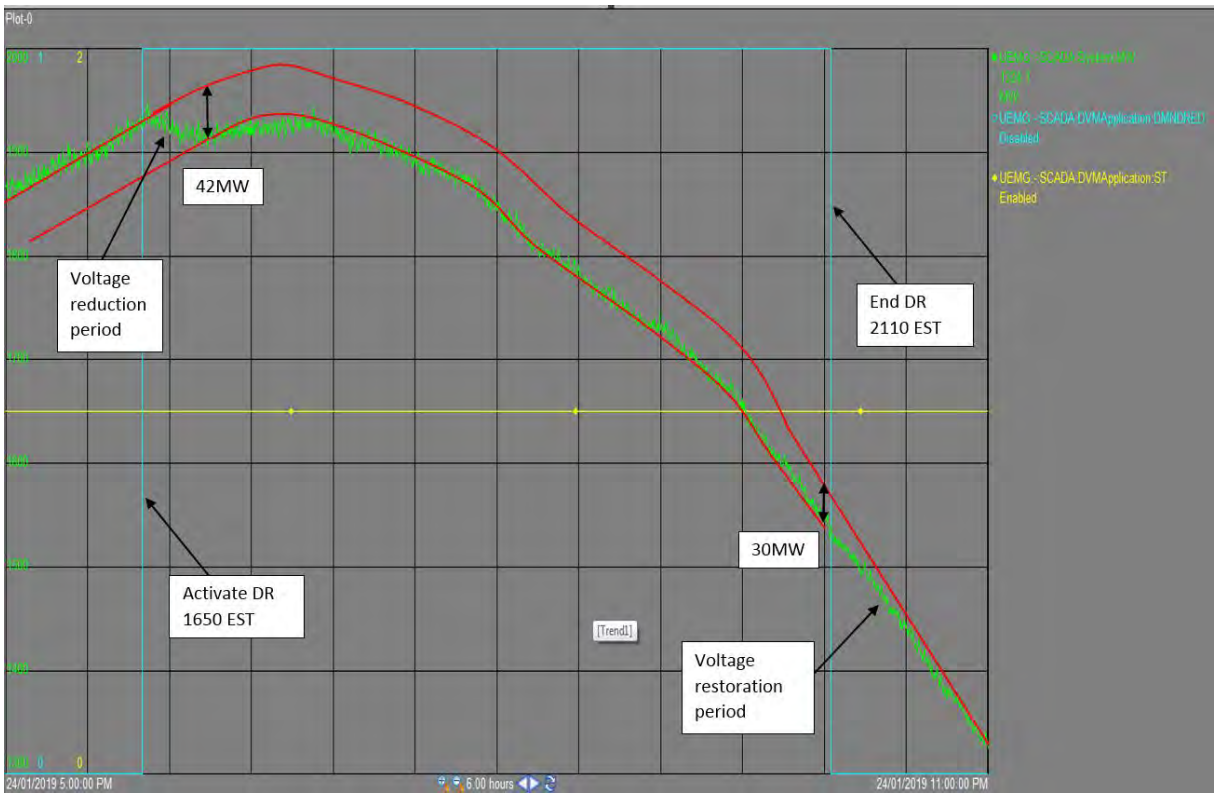


Figure 39 RER Demand Response Window on 24th January 2019 (6-Hour Window)

The RERT services delivered by UE and others on the 24th January was sufficient to avoid the need for load shedding on this day. This was a major achievement for the ARENA programme in delivering its intended objectives and a great outcome for the community.

6.3.2. Second RERT Activation – 25th January 2019

AEMO called a second live RERT activation with UE on 25th January 2018 for a 4.5-hour period starting 1100 market time for a capability of 30MW.

The UE service area demand at the time was 2016MW, higher than the peak of the previous day due to the extremely high overnight temperatures experienced in Melbourne. UE was able to repeat the 42MW of demand response achieved the previous day upon activation on 25th.

Figure 40 shows the activation which occurred on the 25th using high-frequency SCADA metering of the UE service area demand. Activation status of the demand response mode in DVMS is shown in blue and is triggered 5-minutes before 1100 market time (noting that the timestamp on the chart below is in Melbourne local daylight savings time) when we received instruction from AEMO to dispatch. While a 10-minute activation time is required, it should be noted that the activation instruction from AEMO was by way of a phone call at 1055. The normal activation SMS from AEMO was delayed and arrived later.

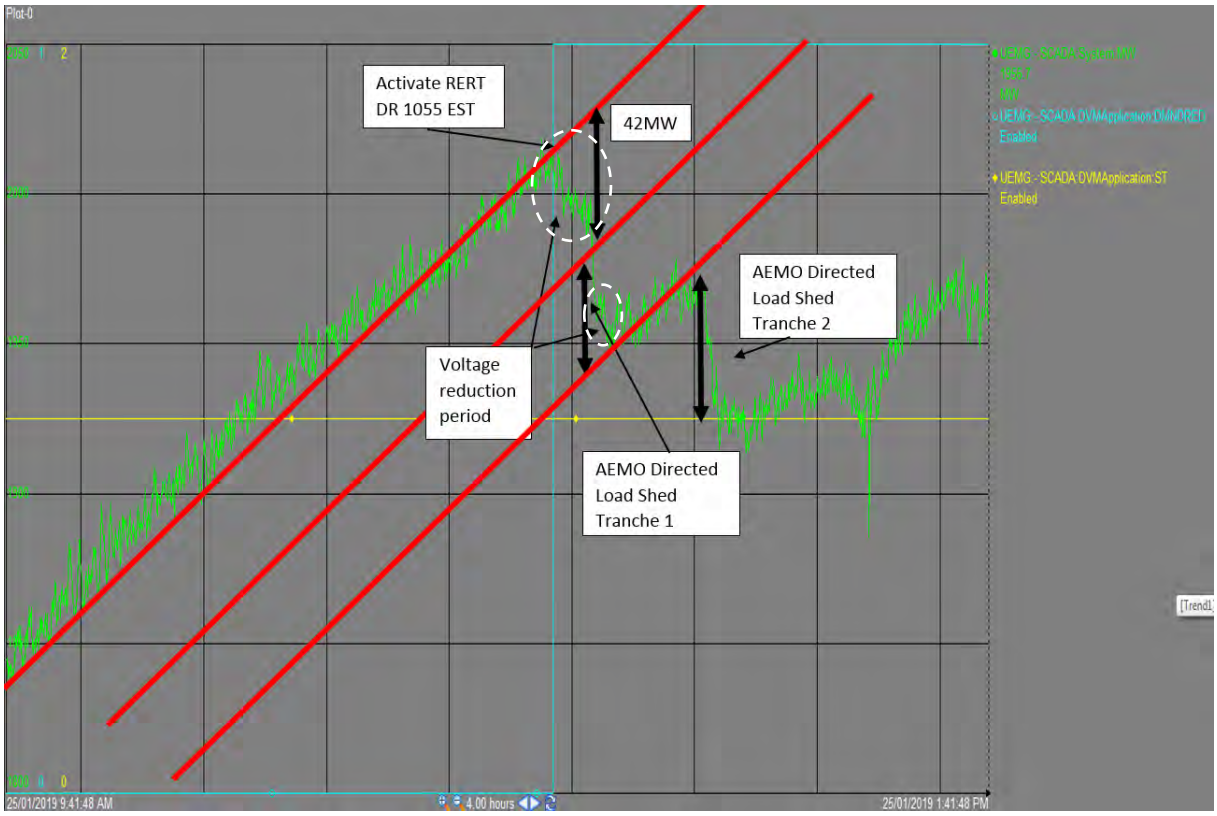


Figure 40 Activation and Load Shedding on 25th January 2019 (4-Hour Window)

While the RERT services delivered by UE and others on the 25th January did not avoid the need for load shedding, the beneficial impact of the demand response in minimising the load shedding can be seen in Figure 40.

The tapping down of the zone substation transformers starts upon activation at 1055, with the voltage reduction arresting the increasing demand (shown in green) at the time, forcing it to decline with a demand response of approximately 30MW by 1104. At 1104 UE received instruction from AEMO via AusNet Transmission to commence load shedding and this is illustrated in the 27MW step down in demand at 1104 indicated by Tranche 1 in Figure 40. Between 1104 and 1110, further tapping down of transformers is occurring to provide a total demand response contribution from voltage reduction of 42MW.

Following completion of all tap downs across the fleet of zone substations at 1110, the demand then begins to rise on its original rate of change (solid red lines), albeit from a point 69MW (comprising of 42MW of demand response plus 27MW of load shedding) lower than what it would have otherwise been. At 1130 UE received instruction from AEMO via AusNet Transmission to commence further load shedding and this is illustrated in the 36MW step down in demand at 1130 indicated by Tranche 2.

The UE demand peaked that day just prior to activation, but would have normally peaked at 2095MW at about 1245 once the cool weather change arrived. This would have exceeded the record maximum demand observed back in 2009.

The reason the UE maximum demand did not reach a new record peak on the 25th is due to the combined effects of the demand response and load shedding and is illustrated in Figure 41.

Without the cool change arriving in Melbourne at 1245, the UE demand would have expected to peak at around 2223MW at 1600.

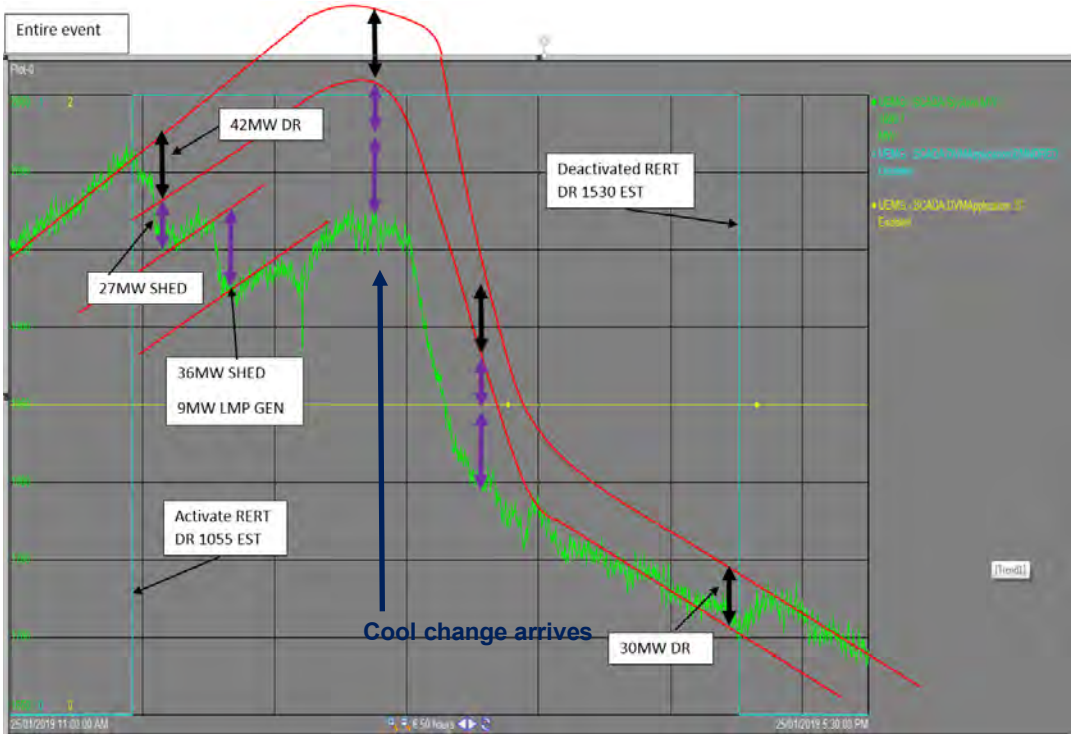


Figure 41 Demand Response Window on 25th January 2019 (6.5-Hour Window)

Figure 41 shows the impact of the demand response (black arrows), the two tranches of the AEMO-directed load shedding (purple arrows) and the rapid reduction in demand upon arrival of the cool change to Melbourne. Load shed during the period was progressively restored with all load restored in full by 1356 market time.

Once again being a long dispatch period, the thermostat effects contributed to a decline in the delivered demand response throughout the duration of the dispatch with the lowest demand response of 30MW delivered at the end of the period. This is illustrated in Figure 42, which shows the voltage restoration period which was triggered at 1532 once UE confirmed with AEMO that the RERT service was no longer needed.

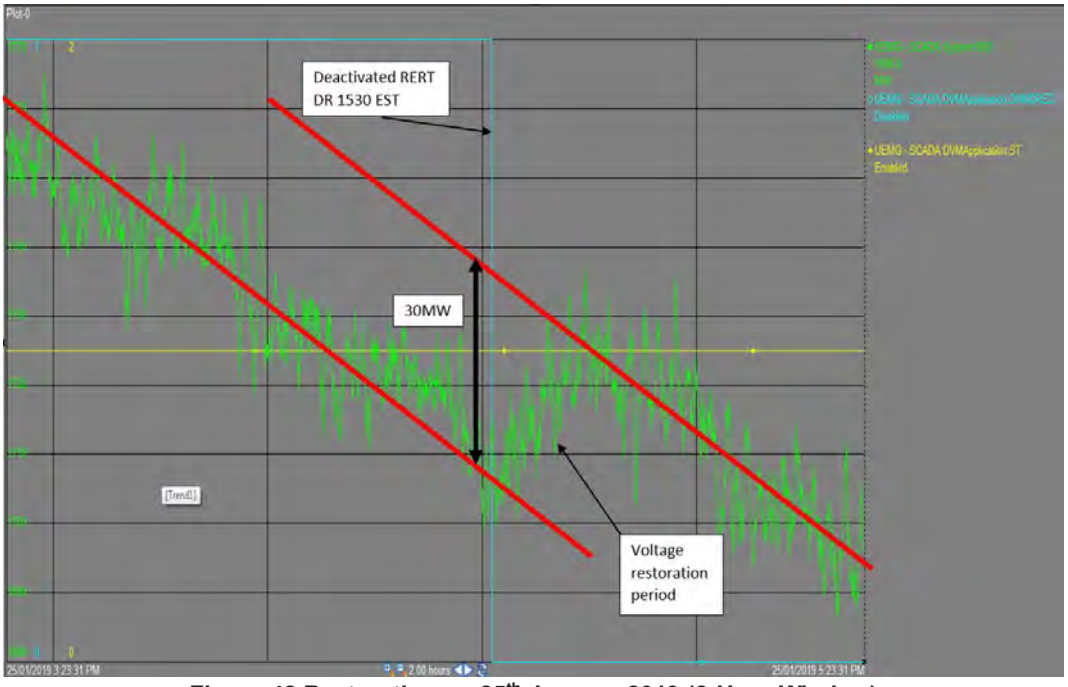


Figure 42 Restoration on 25th January 2019 (2-Hour Window)

6.4. Conclusions

UE plans to continue to participate in RERT beyond the ARENA-funded project using the DVMS to increase supply-demand reserve levels in the NEM to help avoid load shedding. And as a result, UE has been working with AEMO to provide similar RERT services for the 2020/21 summer.

UE also plans to review the operational settings for the DVMS on a regular basis to ensure the maximum benefits are delivered to both customers and its distribution network with respect to steady-state voltage compliance and increasing the DER hosting capacity.

Furthermore, UE takes any opportunities to share the knowledge obtained with the broader industry and others who may have any interest in deployment of similar schemes to DVMS.

7. Knowledge Sharing Activities

Since the commencement of the project, UE has participated in the following events and shared the learnings of this project with the broader industry:

- Presentation on "Voltage-Controlled Frequency Regulation System" at the Electric Energy Society of Australia Conference 2020 (EECON 2020) on 24th-25th November 2020.
- Presentation on "Managing Electricity Demand Through Smart Solutions" at Engineers Australia Webinar on 1st October 2020.
- 4th Australian Distribution Future Network Forum Workshops hosted by Western Power on 10th-11th September 2020.
- AGL and UE Knowledge Sharing Workshop on DVMS Operation on 18th August 2020.
- The 1st South East Councils Climate Change Alliance (SECCCA) Regional Emissions Reduction Stakeholder Workshop on 14th July 2020.
- CitiPower/Powercor and UE Future Network Workshop – Enable a Network that Meets Customer's Needs on 26th June 2020.
- ARENA Demand Response Post-Summer Roundtable on 25th March 2020.
- CitiPower/Powercor and UE Future Network Workshop – Enable a Network that Meets Customer's Needs on 6th March 2020.
- ARENA Year 2 Programme for DVMS Demand Response Workshop between Oakley Greenwood and UE on 17th January 2020.
- UE and AEMO Knowledge Sharing Workshop on 25th November 2019.
- ARENA Insights Forum in Melbourne on 21st November 2019.
- Presentation on "Energy Profiling and Demand" at RMIT Industry Forum on 7th November 2019.
- The 3rd Australian Distribution Future Network Forum in Brisbane on 14th-15th October 2019.
- UE and Power Asset Holdings Knowledge Sharing Workshop on 3rd September 2019.
- CIGRE Australia Conference on Integration of Distributed Energy Resources Asia Pacific 2019 on 20th-21st August 2019.
- Annual meeting of CIGRE Australia Panel C6 Active Distribution Systems and Distributed Energy Resources on 19th August 2019.
- UE and AusNet Services Knowledge Sharing Workshop on 5th August 2019.
- UE and SA Power Networks Knowledge Sharing Workshop on 1st July 2019.
- RMIT Industry Lecture for Advanced Power System on 27th May 2019.
- TasNetworks Future Networks Distribution Forum in Hobart on 9th April 2019.
- ARENA Demand Response Portfolio Knowledge Sharing Workshop on 27th March 2019.
- UE and AGL Demand Response Knowledge Sharing Workshop on 26th March 2019.
- UE and SA Power Networks Knowledge Sharing Workshop on 7th February 2019.
- UE and AGL Demand Response Knowledge Sharing Workshop on 6th February 2019.
- Workshop with University of Melbourne to relating to learnings from the UK CLASS initiative compared to learnings from DVMS on 3rd December 2018.
- ARENA Knowledge Sharing Insights Workshop held by ARENA in Sydney on 30th November 2018.
- SA Power Networks Future Networks Distribution Forum in Adelaide on 25th October 2018.

- Workshop on investigations into revised baselining methodologies on 3rd and 24th September 2018.
- Presentation on "Large-Scale Smart Meter Demand Response Program" at Energy Networks 2018 Conference in Sydney on 7th June 2018.
- Presentation on "United Energy's DVMS Technology and Learnings from the Programme" at Tokyo Electric Power Company (TEPCO) and UE Knowledge Sharing Workshop on 24th May 2018.
- Presentation on "United Energy's DVMS Technology and Learnings from the Programme" at AGL and UE Knowledge Sharing Workshop on 12th April 2018.
- Oakley-Greenwood Interview on Baseline Learnings for Investigation into Revised Baselining Methodologies on 11th April 2018.
- ARENA Demand Response Participant Workshop held by ARENA in Melbourne on 8th March 2018.
- Updated the knowledge sharing webpage on the UE website for the purposes of sharing our project performance reports and provided input into the ARENA knowledge sharing insights website content.

8. Glossary of Terms

The following terms are referenced within this document:

Term	Description
AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure (Smart Meters)
ARENA	Australian Renewable Energy Agency
DR	Demand Response
DVMS	Dynamic Voltage Management System
HV	High Voltage
LV	Low Voltage
MW	Mega Watt
NAP	Network Analytics Platform
NCC	Network Control Centre
NEM	National Electricity Market
OLTC	On-Load Tap Changer
PV	Photo-voltaic
RERT	Reliability and Emergency Reserve Trader
SCADA	Supervisory Control and Data Acquisition
UE	United Energy
UoW	University of Wollongong
VRR	Voltage Regulating Relay