Dynamic Limits

THE ROLE OF DECENTRALISED CONTROL FOR MANAGING NETWORK CONSTRAINTS FOR DER ON REGIONAL, RURAL, AND REMOTE NETWORKS

AUGUST 2020

Acknowledgements

This project received funding from the Australian Renewable Energy Agency under the Advancing Renewables program.

The project was supported by partners Essential Energy, SAGE, UniSA, and Opto22.

The project would like to thank everyone who participated directly or indirectly in the project. In particular, Joshua Harvey, Peter Bereicua, Scott Taylor, Clint Collins, Adam White, Brad Thomas, Greg Bell, Ian Askell, Bill Howell, Alexei Watson, Doug Wray David Zurillo and Jayne Jardine from Essential Energy, Dr Emily Hilder, Dr Peter J. Murphy, Dr Frank Bruno, Dr David Whaley, and Mark Saunders from the Future Industries Institute at UniSA, Dr Peter Pudney and Dr Peng Zhou from the Centre for Applied and Industrial Mathematics at UniSA, Andrew Downs, Paul Moore and Justin Kahl from SAGE, Stephen Earle from Opto22, Andrew Mitchell, Bernhard Shepard from ERM Power, Claire Richards from EnelX, Mark Wilson from AER, Alex Dinovitser, Sarah Chalmers, Sid Whiting, Skye, and Jack.

EXECUTIVE SUMMARY

Dynamic Limits Pty Ltd, supported by Essential Energy, SAGE Automation, Opto22, and UniSA, has received ARENA funding to conduct a feasibility study on a proposed Decentralised Dynamic Limits Control Scheme (the DDL Control Scheme) for implementing dynamic control for Distributed Energy Resources (DER) to increase the hosting capacity of electricity networks.

The report's specific hypothesis is that the decentralised control of DER for the management of local network constraints can provide a range of benefits, in particular for regional, rural, and remote network sections. These networks were of particular focus because they capture the majority of Australia's solar irradiance while also representing the weakest network sections, with the poorest communication availability, and are resource constrained (in terms of revenue per km of network managed).

Approach

To place this project in an appropriate context, a review of a range of other initiatives, with particular attention given to the Open Energy Networks (OpEN) Initiative, was first undertaken.

A Technical Review Group among project partners was established to provide continuous input and feedback. A pre-mortem workshop was also held with a broader group of subject matter experts to identify issues likely to be encountered during implementation.

A range of external stakeholders including technology developers, retailers, generators, networks, and regulatory bodies were all consulted regarding the Scheme and the barriers that may be encountered when attempting to realise the Scheme's benefits.

Report Structure

The report begins by defining some key terms and outlining the key scope exclusions. In particular, a distinction is made between DER Control for Local Network Constraint Management (ensuring that DER do not contribute to local network constraints being exceeded) and DER Orchestration (activating DER as in response to some other agenda). A range of terms used to describe control schemes are also introduced and defined.

The report then outlines and explains network constraints, covering voltage constraints, thermal constraints, and how the two combine to create an operational window within which the net load (including DER) must remain.

The report then reviews existing approaches to DER Management, including the use of network augmentation, static limits, and, in particular, the Power Quality (PQ) Response Modes under AS4777. These existing approaches are found to be lacking. Although the PQ Response Modes implement some dynamic control responses, scheme participation is not mandatory, default settings offer minimum relief for networks with higher average voltage levels, and network operating states at constraints are not known. The PQ Response Modes will assist to reduce over-voltages within the installations to which they are applied, but do little to increase the hosting capacity of networks or manage constraints.

A number of key publications from the Open Energy Network initiative are then reviewed alongside some international publications such as IEEE's 2030 Standard. These are used to ensure that the DDL Control Scheme proposed can address concerns raised, be applied within the frameworks developed, and integrate with the frameworks for implementing a distribution system operator and achieving the smart grid functionality of the future.

The report then outlines the principles applied in developing the DDL Control Scheme, explains the Control Scheme itself, highlights the anticipated benefits of implementation, and details a pathway to implementation. Two site-specific studies are then conducted to examine the benefits of implementation in detail.

Control Scheme Feasibility

The DDL Control Scheme examined as part of this report has four key components — a Network Sensor, DER Controller, Open Network Data Platform (ONDP), and Dynamic Limits Profile (DLP).

The report findings confirm the hypothesis that the decentralised control of DER for the management of local network constraints can provide a range of benefits, particularly for rural and remote networks.

DER Management tasks are found to be most effectively implemented when this is done at the lowest level of the control hierarchy using decentralised control. Further, this approach is most beneficial for simple, radial, rural networks, and can overcome the specific challenges these networks present.

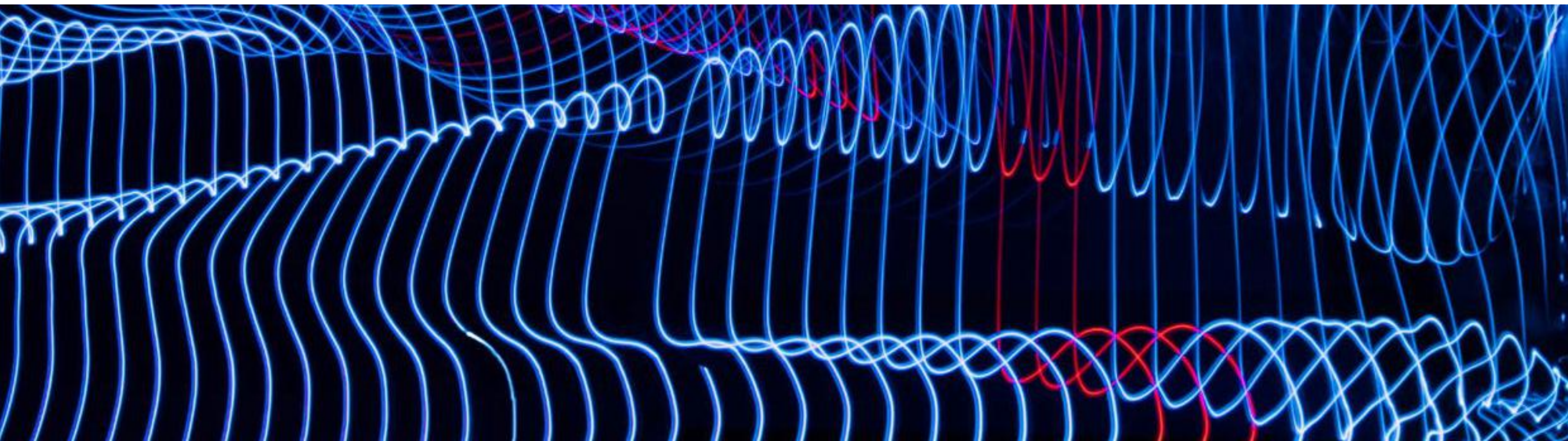
The report also confirms the benefits of implementing dynamic operating envelopes to manage network constraints and unlock the DER hosting capacity of distribution networks. Modelling undertaken as part of this project illustrate achievable DER hosting capacity increases from 120% to over 400% above results expected by applying static limits and traditional connection management approaches, with only minimal curtailment of energy. The site-specific studies also reveal the importance of considering side constraints, such as the 3% voltage change rule and the transformer configuration (e.g. tapping settings; single- vs. three-phase).

Benefits

The primary benefit of the DDL Control Scheme is that it decentralises the management of local network constraints for simple rural networks and — by placing the management of network constraints at the lowest control level — ensures that this control agenda is enforced.

The scheme can also autonomously curtail DER capacities inside local network constraints without requiring network models, while simultaneously interfacing with slower, remote DER Orchestration platforms to facilitate any other control agenda, provided it does not exceed local network constraints.

The report highlights a range of additional benefits that arise under the DDL Control Scheme. The scheme can address the challenges of Latency Cascading, Hidden Coupling, and Tier Bypassing highlighted in the Newport Review commissioned as part of the OpEN Initiative. The use of Network Sensors to improve network visibility removes the need for up-to-date network models and contributes to the achievement of “least regret” capabilities outlined in the OpEN Initiative. The visibility of DER behaviour and current operating states (for both compliance and management) is increased. The solution is robust and resilient to failure and the use of Open Source functionality and specifications for the DER Controller also improves Consumer Energy Choice.



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ABBREVIATIONS

ADMD	After Diversity Maximum Demand
ADMS	Advanced Distribution Management System
AER	Australian Energy Regulator
AEMO	The Australian Energy Market Operator
API	Application Programming Interface
CBEMA	Computer Business Equipment Manufacturers Association
DDL Control Scheme	Distributed Dynamic Limits Control Scheme
DER	Distributed Energy Resources
DLP	Dynamic Limits Profile
DMS	Distribution Management System
DNSP	Distribution Network Services Provider
DSO	Distribution System Operator
ENA	Energy Networks Australia
FCAS	Frequency Control Ancillary Services
IIoT	Industrial Internet of Things
ITIC	Information Technology Industry Council
LTS	Long Term Study
LV	Low Voltage
MV	Medium Voltage
MDI	Maximum Demand Indicator
NEM	National Electricity Market
NSW SIR	NSW Service & Installation Rules
ONDP	Open Network Data Platform
OpEN	Open Energy Networks
PQ	Power Quality
PV	Photovoltaics
SCADA	Supervisory Control and Data Acquisition
SGAM	Smart Grid Architecture Model
SGIRM	Smart Grid Interoperability Reference Model
SWER	Single Wire Earth Return
UOW LTS	University of Wollongong Long Term Study
VPP	Virtual Power Plant

01 INTRODUCTION

1.1 PROJECT SCOPE AND HYPOTHESIS

The Dynamic Limits project has undertaken a desktop analysis to investigate the feasibility of a DDL Control Scheme that uses distributed control to implement dynamic Distributed Energy Resources (DER) limits and its potential suitability for Essential Energy's network characteristics and Distribution System Operator (DSO) strategy.

The project's specific hypothesis is that the decentralised control of DER for the management of local network constraints can increase the hosting capacity of networks as well as provide a range of benefits, in particular for rural and remote networks.

The project's goal was to understand the benefits of the Scheme and its potential impact (in terms of managing network constraints and increasing the hosting capacity of networks) and to identify any roadblocks, barriers to implementation, or other issues of concern.

The project also examined the general benefits of dynamic limits management for DER on some typical rural supply scenarios.

In all aspects of the study, a focus was retained on how the Scheme would interact and interface with other (centralised) DER control platforms implementing DER Orchestration and DER Optimisation agendas (See Section 1.3 for a discussion of these terms), which may or may not have visibility or control over local network constraints in any location.

The adaptation of existing network modelling suites (PSS SINCAL, PowerFactory) to better model dynamic DER limits was beyond the scope of this project.

1.2 PROJECT APPROACH

Stakeholders at Essential Energy formed a Technical Review Group to consider the DDL Control Scheme and also hosted a feedback workshop with attendance drawn more widely from other departments within Essential Energy. The network planners also provided network information to facilitate the modelling of benefits for applying dynamic DER export limits to manage DER in rural supply scenarios.

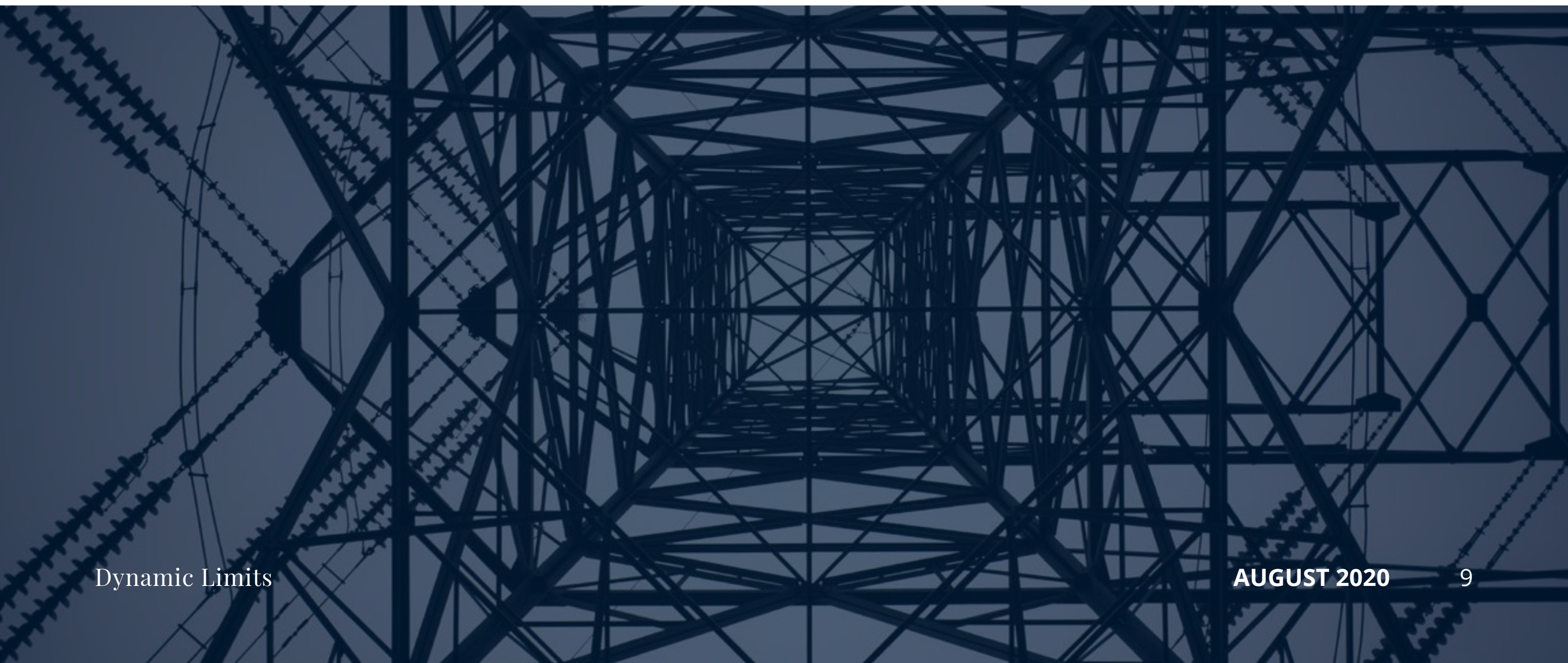
Scheme assessment and feedback was provided on the merits and anticipated difficulties of the proposed scheme and this was incorporated into the analysis.

Further, a range of external stakeholders including technology developers, retailers, generators, networks, regulators, and market operators were all consulted regarding the Scheme. The barriers that may be encountered when attempting to realise the Scheme's benefits were acknowledged and also incorporated into the report.

The project also identified the key observations and conclusions from other industry publications and initiatives developing and proposing (potential future) frameworks and approaches for the management of dynamic DER limits.

The project developed an overview specification for the DDL Control Scheme and a description of the key scheme components. The Scheme was then examined in the context of Essential Energy's rural and remote network footprint. This included specific consideration of the unique challenges that rural and remote networks present to the dynamic control of DER (see Section 6.5).

The project concludes by examining the implementation of the Control Scheme at two sites (using three network models) on Essential Energy's Network, using the concept of an operational window to understand the impact of the Scheme in each supply context modelled.



1.3 DEFINING CRITICAL TERMS

This section defines a number of terms used throughout the document that warrant specific definition beyond those provided in the Glossary.

1.3.1 OPTIMISATION, ORCHESTRATION, AND LOCAL CONSTRAINT MANAGEMENT

This document distinguishes between three key terms: DER Orchestration; DER Control for Local Network Constraint Management; and DER Optimisation. This section defines each and relates them to language and definitions used in the Open Energy Networks (OpEN) Initiative.

DER Orchestration

In this document, DER Orchestration will be used to refer to the control of a group of DER over a potentially wide geographic area to achieve a specific outcome.

Examples might include a fleet of DER as part of a Virtual Power Plant (VPP) acting in concert in response to a wholesale market price spike or a whole Bulk Supply Point region being asked to contribute to peak shaving existing infrastructure to defer traditional network augmentation. However, there are numerous other examples of the functions DER Orchestration can provide. These range from network support services (e.g. voltage and peak shaving support) and power system support (e.g. Frequency Control Ancillary Services and other ancillary services) to market support (e.g. providing physical hedges for retailers).

Further, the operational area of a DER Orchestration event can vary from small multiples of DER installations, through to clusters in a local area, to multiple groups in a locality, to a whole zone substation or bulk supply area, up to a scale impacting the whole of the National Electricity Market (NEM).

The OpEN Initiative uses the terms DER Orchestration and DER Optimisation interchangeably to describe this function; however, their definition includes both the aggregation of a range of wholesale and Frequency Control Ancillary Services (FCAS) — and in the future potential network services — bids from DER while also considering network constraints. This report treats the management of local network constraints as a separate task (see the following section).

DER Control for Local Network Constraint Management

In this document, the term DER Control for Local Network Constraint Management (sometimes shortened to DER Management) refers to the dynamic management of DER to ensure that the technical constraints of the electricity network are not exceeded.

The potential for the technical constraints of the network to be exceeded is influenced by the number of customers with DER and the combined capacity of that DER. DER Orchestration events may also contribute to network constraints being exceeded by coordinating responses and removing the diversity of demand that is traditionally present on electricity networks (see Section 2.1.2).

DER Management must ensure that network constraints are not exceeded during both DER Orchestration events and at any other time. The task of DER Management is akin to what the OpEN initiative refers to as the optimisation of the "operating envelopes of distribution network end-customers."[1] In this document, the task of DER Management extends to also include consideration of how this operating envelope is enforced.

DER Optimisation

The term DER Optimisation refers to the co-optimisation of the DER Orchestration tasks and the priorities of DER Control for Local Network Constraint Management. The term DER Optimisation is most closely related to what the OpEN Initiative has labelled "Distribution Level Optimisation"[2] or "DER Optimisation at the distribution network level"[3].

Operating Envelopes

A key term often used when describing dynamic DER limits for networks is "operating envelope". In the context of DER Management, operating envelopes establish the limits within which customers' DER must operate for the safe and secure running of the network and the overall electricity system. DER Control for Network Constraint Management is thus achieved through the provision and enforcement of Operating Envelopes for all DER.

Illustrative Example

An example makes the distinctions between these definitions clearer. In the event of a wholesale market price spike, a DER Orchestration task (initiated by energy aggregators or retailers with control over DER recruited to that scheme) may be to export as much energy to the network as possible.

However, in certain sections of the network (e.g. those with large amounts of solar and/or battery adoption and/or pre-existing network constraints being approached), if all DER were to export at this level, a network constraint would be exceeded.

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[1] This is the second "activity" under the "DER Optimisation at the Distribution Network Level" function. See p. 107 of the EA Technology Report, available here: https://bit.ly/36f2ceS

[2] Under Function 6 of the "Key Functions in DER Optimisation" as outlined on page 30 of their Consultation Report, available here: https://bit.ly/2WOn49x

[3] The name of Function 6 under the AE Technologies Report available here: https://bit.ly/36f2ceS

Ensuring that the network constraint is respected is a task for DER Control for Local Network Constraint Management. This is done by establishing an Operating Envelope for all DER, including the DER involved in the DER Orchestration event.

Determining which of the wholesale market bids made by the retailers and aggregators should proceed given the existence of a network constraint is a DER Optimisation task, likely undertaken by a DSO.

As this example makes clear, the tasks are inter-related and any actor or system addressing one task must interface with actors and systems implementing the other.

HIGHER AND LOWER CONTROL LEVELS

Section 5.2 of this document outlines work undertaken by others that establishes the need for a control hierarchy. The terms higher and lower level are used in this document to describe the position on the control hierarchy at which an event is occurring.

In this report, the term higher refers to the tasks and agendas undertaken at the highest levels of this hierarchy. Examples of this include the Australian Energy Market Operator's (AEMO) wholesale market and power system operations functions. These tasks affect the whole of the NEM and thus can be described as a high-level function.

Ensuring that the voltage on a single section of local 230/400V network is within the allowable ranges of network can be viewed as a lower level task in the control hierarchy. Lower level does not mean that the importance of the task is subordinate to higher level tasks (in fact, this paper takes the position that the opposite is true — see Section 6.1). Rather, it simply states that this task is occurring at a lower level in the control hierarchy.

CENTRALISED, DECENTRALISED, AND HYBRID CONTROL SOLUTIONS

The terms centralised and decentralised control refer to whether or not the controlled devices or variables are managed in groups or en masse from a remote platform (i.e. centralised) or managed locally in an autonomous or semi-autonomous fashion (i.e. decentralised).

It is important to note that the terms centralised and distributed control do not refer to the broader topics of centralised computing and distributed computing (despite there being considerable overlap).

There is overlap between the concepts of centralised and decentralised with the notion of the hierarchy of control. The terms are similar to, but distinct from, the terms higher level and lower level.

The following section defines centralised and decentralised control schemes as used in this report and then distinguishes the concepts from high and lower level functions through a series of illustrative examples.

Centralised Control

Centralised Control systems are characterised by the aggregation of operating data to a single, central location, processing site, or controlling entity. The control objectives for any controlled devices are defined centrally. The aggregated data is processed centrally to determine any required set points or commands needed for controlled devices or variables to perform in a manner required to meet the control objectives. So, the control outcomes, targets, and objectives are all set centrally, and all controlled variables or equipment have commands communicated to them from this central location.

Data stores are also maintained — and owned — centrally (ignoring off-site storage carried out for data security, redundancy, or archive purposes). In a centralised control scenario, the controlled devices or controlled variables distributed remotely from the central platform do not undertake local processing that leads to any aspect of local autonomous control.

Centralised control platforms tend to be focussed on (and best suited to) control objectives with a more global focus, involving greater scope or reach that tends to place them higher in the hierarchy of control platforms.

Decentralised or Distributed Control

Decentralised or Distributed Control (the terms decentralised and distributed are used interchangeably in this document) involves autonomous controllers distributed throughout a system that operate in some manner that does not require supervision or control from a central platform to carry out some key, local control function.

In some cases, distributed control may incorporate inputs or outputs from or to central control platforms to achieve some control tasks (as outlined in the hybrid example below) and these inputs will usually relate to theme or set point changes relevant to some control objective associated with a global or wider area control function. These centrally provided control inputs can guide, alter, or re-purpose the local control action that is otherwise occurring autonomously.

Decentralised control is suited to faster, more reliable, autonomous management of local — or lower level — control issues. These issues may not contribute to any strategic or global initiative but are nevertheless critical to the local system being able to function safely within limits. Decentralised control thus tends to relate to control objectives that are lower in the hierarchy of control platforms.

Distributed controllers are often used in processes that require enhanced reliability, security, faster local processing in real-time, or greater customisation options at each locality. The enhanced reliability occurs because the process control is distributed to all the nodes in the system, removing a single point of failure.

Example: High Level Problems with Centralised Control Solutions

For example, AEMO's wholesale market pricing and dispatch function (taking price bids from generators and deciding which generators will be deployed to produce electricity) is a high-level function as it effects the entire NEM. It also occurs centrally; AEMO is the sole actor undertaking this function and communicating the results to all other market participants.

Example: Low Level Control Problem with a Decentralised Control Solution

The Power Quality Response Modes outlined in Section 3.3 of this report are examples of a lower level task occurring with decentralised control. The task is low level as it only affects a very small part of the network (in this case, a single inverter at a DER installation). A decentralised controller — the local inverter — is used to determine that a response is necessary and to implement that response.

Example: Control Level and Solution Can Be Different

The level of the control problem and the level that implements a control solution do not necessarily need to align. For example, a Distribution Network Services Provider (DNSP) may have manual control (via SCADA) of large embedded generators. If the local voltage rises too high or a thermal constraint is being approached, the DNSP may send a SCADA signal to curtail the embedded generator.

This is an example of a low-level control problem (local voltage) being solved via a centralised (the DNSPs control centre) control solution.

Example: Hybrid Control Solutions

Centralised and decentralised control are not, however, an either/or proposition. There is the potential for solutions to problems to be a hybrid of the two. One example of a hybrid control solution is contingency FCAS.

The problem — the management of grid frequency throughout contingency events (such as the loss of a major generator) — is a high-level control problem affecting the entire NEM.

The contingency FCAS requirements are determined and set centrally by AEMO. The system requirements (quantity and response time) are anticipated and identified in advance, while considering the entire NEM and the legislated requirement to return frequency to the normal operating bands within five minutes of a credible contingency event. Participants that make successful bids are notified by AEMO that they are to provide this service in the relevant market interval. This is the centralised aspect of the control solution.

However, the implementation is done via decentralised control. Technologies that can locally detect a frequency deviation are used to determine if and when a response in a manner that corrects the frequency is required. This is the decentralised aspect of the control solution. The use of decentralised and control solutions together thus creates a hybrid solution.

For example, battery systems providing contingency FCAS (such as the Hornsdale Power Reserve in South Australia) continually monitor grid frequency and, if it crosses a pre-determined threshold, react appropriately. The use of decentralised control in this manner ensures that the battery systems are able to respond in a fraction of a second. If AEMO were to monitor grid frequency and then send a control signal to all participants that a reaction is required, this would be a centralised control solution. However, this approach would prevent such fast reactions to frequency events, due to delays caused by Latency Cascading, which is described later in this report (see Section 5.2.1).

02 NETWORK CONSTRAINTS

Rural and remote distribution networks are typically radial, with a backbone constructed to carry the load to a number of spurs that then supply customers remote from the backbone. In some cases, the spurs may be strong enough to support a large proportion of the feeder load if they form an interconnection with another feeder, but more commonly, the construction of spurs is only adequate for the load that is normally connected. The further away from the zone substation a customer is connected, the more lightly built and electrically weaker the distribution network.

The combination of distance, construction and conductor electrical characteristics determines the total impedance of any distribution feeder. This value, in combination with the operating voltage and other treatments such as the existence of voltage regulators, will determine what load can be carried.

The smaller the conductor, the longer the line and the weaker the feeder. A site with weak supply will have a higher source impedance and a strong site will have a lower source impedance. Higher impedance causes larger voltage drops for the passage of current. Short, strong feeders tend to reach their current (thermal) limit before they lose too much in voltage drop along the line. Long, weak feeders suffer a relatively large amount of voltage drop for smaller current flows and this means they usually reach their limits of voltage drop before their thermal limits are exceeded.

The reliability performance of feeders is also affected by feeder length. The longer a feeder is, the more reliability issues we expect to encounter.

2.1 THERMAL CONSTRAINTS

This section gives an overview of thermal constraints, conductor sizes that affect them, and how the principle of After Diversity Maximum Demand (ADMD) is used to increase asset utilisation of networks. It also introduces potential constraints when diversity is removed by, for example, high penetration of large solar systems or DER Orchestration events.

CONDUCTOR SIZES & LOCAL CONSTRAINTS

The overall capacity constraint on load or embedded generation is primarily a local issue for small scale loads and DER because the overall feeder capacity far exceeds the capability of typical small-scale generation or load.

Thermal ratings of conductors vary considerably with design temperature, ambient temperature, wind speed, and the level of insolation. Table 1 illustrates some typical conductors used in the construction of the backbone of Essential Energy feeders and their thermal rating at midday with an ambient temperature of 35°C, 50°C design temperature and 0.5m/s wind speed.

CONDUCTOR	STRANDING	MATERIAL	50C CURRENT RATING (A)	11KV APPARENT POWER RATING (MVA)	22KV APPARENT POWER RATING (MVA)
Mercury	7/4.50	AAC	144	2.74	5.49
Fluorine	7/3.0	AAAC/1120	96	1.83	3.66
Neon	19/3.75	AAAC/1120	184	3.51	7.01
Mink	6/1/0.144	ACSR/GZ	105	2	4
Copper	7/0.104	HDBC	109	2.08	4.15
Copper	19/0.064	HDBC	110	2.1	4.19

Table 1 - High Voltage Conductors and (Thermal) Energy Transfer Capability (short distances)

Table 1 indicates that the conductor capacity when used at the typical 11kV or 22kV distribution feeder level is many times greater than the size of the typical small scale embedded solar system connected to the 230/400V low voltage network.

In the case of individual small-scale DER systems, constraints on the ability of the high voltage distribution network to absorb the power generated by DER systems are more likely to be preceded by constraints that occur at a local level (such as local, low voltage segments or mains).

AFTER DIVERSITY MAXIMUM DEMAND (ADMD)

The principle of ADMD is used to reduce the conductor sizes to levels of demand that the network can expect, rather than the maximum theoretical demand that a network would experience if all connected appliances were switched on simultaneously.

A circuit supplying a single item of equipment would need to be sized to accommodate the nominal load of the equipment. This would allow the equipment to operate at full load and the conductor to be adequately sized and protected.

When more than one item of equipment is connected, the circuit current could be simplistically assessed as the sum of the individual maximum load currents. This would provide a safe and conservative assessment. However, it would not be realistic or economic because simple sums of this type do not take into account the normal operating conditions, which often feature load diversity. All equipment is not operating simultaneously at full load, nor do all individual loads operate at the maximum loading level for long periods.

Accepting these effects of load diversity, the current in any circuit is estimated using factors that accommodate known or typical historical diversity. The conductor size is then selected using this more realistic estimation of likely maximum total circuit load.

This application of a diversity factor to customer loads connected to a distribution feeder allows the feeder to be constructed out of a conductor many times smaller than what would be required if all the (maximum) loads on the feeder were to be summed as if they were going to occur as coincident load. The non-coincidence of loads on a distribution feeder allows the utilisation of a diversity factor between loads and this leads to the construction of more economical networks that are still able to handle the maximum annual load events.

As an example, a feeder with 500 customers, each of which has a peak single-phase load of 15kVA (63A at 240V), would result in a feeder load of 500*15kVA=7.5MVA or a phase current of 393A at 11kV. This coincident load scenario would suggest a feeder current far above any of the backbone feeder current ratings shown in Table 1, and — if accepted as a realistic maximum load estimate — would result in the uneconomic design and construction of a distribution network. The network constructed to meet a coincident load condition of that size would be very much underutilised in real life loading conditions. With the application of appropriate diversity factors, it is possible to optimise the size of network equipment and still meet the actual demands of the connected load.

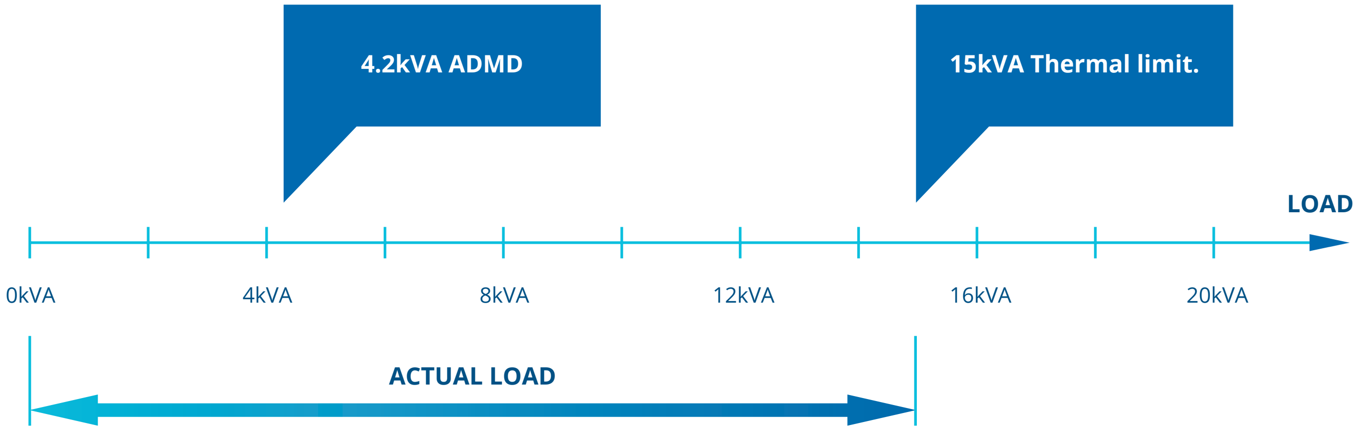
So, a more realistic approach is taken with the assumption of ADMD values for each particular customer type. ADMD figures are effectively an average of the maximum load each customer may be expected to contribute to the total annual maximum demand for that region or feeder.

ADMD values are much lower than the potential maximum demand for any individual customer. The minimum size for a domestic connection in NSW of 63A (16mm2 Cu XLPE or 25mm2 Al XLPE as per NSW SIR 3.4) would imply an absolute limit of just over 15kVA per customer. The application of this diversity at an individual customer level allows the hierarchical selection of equipment in the supply chain to be sized appropriately, allowing efficient utilisation of resources.

Figure 1 outlines the potential range of loads for a customer site, marking both the thermal limit and the after diversity maximum demand. It is important to note that, at any time, the actual load of an individual customer may be at any point between zero and the thermal limit imposed by a fuse or other protective device. Once a group of customers are aggregated, diverse usage patterns begin to emerge that allow assumptions to be made about the amount of load they will consume as a group.

Domestic Customer Load Capacity

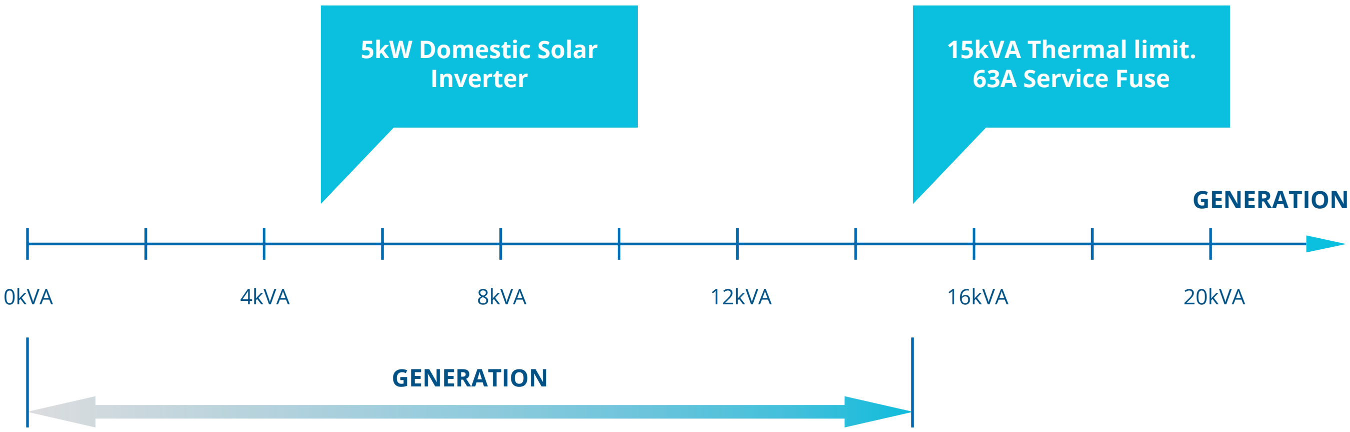
Figure 1 - Relationship between Capacity and Demand



APPLICATION OF THERMAL CONSTRAINTS TO DER

Export Capacity

Figure 2 - Export Capacity at a Domestic Connection



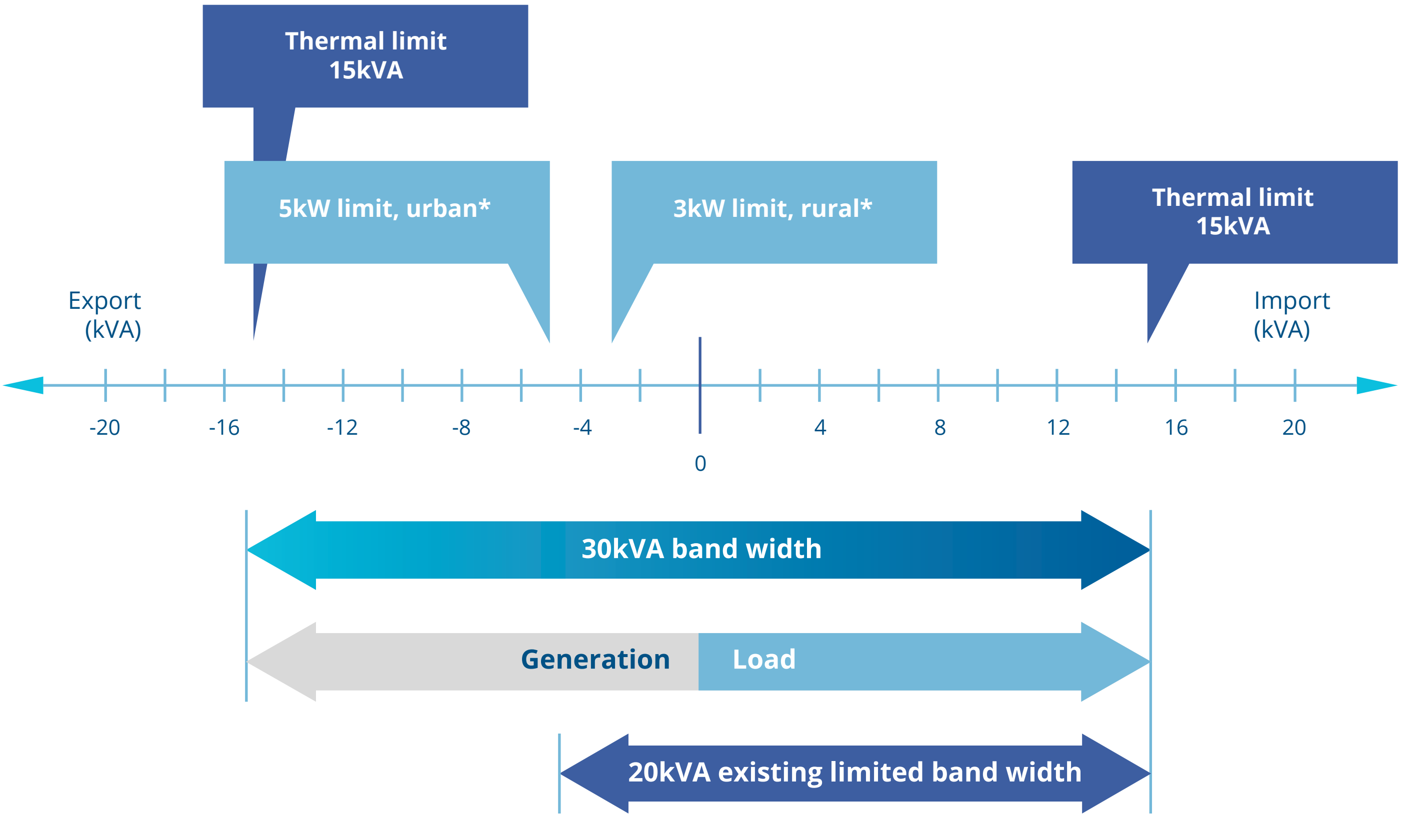
In a similar manner, when considering thermal limits, the amount of generation a customer might export to the grid is bound by a thermal limit based on the current-carrying capacity of the connection; this is illustrated in Figure 2. There is a symmetry between the limits in Figure 1 and Figure 2, as the same thermal limit applies to both import (load) and export (generation) of energy from a customer connection. Another similarity is that the amount of generation capability at any time is unknown; again, general assumptions can be made about generation patterns based on time of day and potential energy storage system performance.

Adding Figure 1 and Figure 2 together provides the full picture of the potential (thermal) capacity available at a single site. This is illustrated in Figure 3. With only the thermal limits in place, there is a total range of capability of 30kVA, import or export. The capacity for export is not the same as the generation capacity as, under most conditions, there will be some consumption on site for standing loads. If the full range of thermal capability were to be utilised, an oversized generator could be installed at the point of connection and limited under no load conditions.

It is important to note that Figures 1 to 3 only examine the thermal capacity at an installation. Voltage constraints are also a concern and are addressed in the next section.

Domestic Connection Thermal Capacity

Figure 3



2.2 VOLTAGE CONSTRAINTS

This section outlines how voltage constraint arises and the various standards that set allowable voltage ranges.

The thermal limit of a connection is one of the two limiting factors that govern the capability of the connection. The other constraint relates to voltage limits and these include upper and lower bounds on voltage magnitude, and voltage change limits.

The characteristics of voltage changes, the impacts on power quality, and the standards that relate to this is a broad and complex subject in itself. Section 10.2 of this report describes just one 'Side Constraint' applied to DER installations by some DNSPs, which is referred to in this report as the Voltage Change Limit rule, which further acts to limit the allowable size of DER installations.

Under real power import conditions, the supply system impedance will cause the voltage at the DER installation to fall, and under real power export conditions, the system impedance will cause the voltage to rise. The change in voltage due to import or export is also impacted by the power factor or reactive power import or export at the location and the inductive components of the supply system impedance.

The voltage range experienced by customers at any connection point on the network needs to be of sufficient quality to allow the correct operation of equipment without damage.

ALLOWABLE VOLTAGE RANGE

The allowable voltage range in Australia changed from a 240V nominal to 230V after the adoption of AS60038:2000. However, there are a number of other standards and documents that define allowable voltage ranges. This section outlines the various standards and voltage ranges they define.

The 230V Nominal Supply Voltage

Traditionally, the supply voltage in Australia was 240V, with +6% / -6% defining an allowable range of 226V to 254V. Average supply voltages in the range 240V to 250V are still common.

However, a 230/400V nominal supply has now been adopted, meaning that the nominal single-phase supply voltage is now 230V in Australia, not 240V as it was prior to the adoption of AS60038:2000.

AS 60038:2012 Standard Voltages defines allowable steady state limits for public electricity systems in Australia as 230 volts (+10%, -6%) and this defines an allowable range, measured at the installation main switch/meter board, of 216V to 253V.

The NSW Service & Installation Rules (NSW SIR) also references this standard AS 60038 Standard Voltages and AS 61000.3.100 Steady State Voltage Limits and refers throughout the NSW SIR accordingly to 230/400-volt supply (and not the historical 240/415-volt supply).

The Australian Wiring Rules (AS/NZS 3000:2018) also references AS 60038 in the same way.

Similarly, DNSPs will also typically adopt these standard supply voltage definitions into their internal policy and procedure documents. For example, Essential Energy has created an Electricity Supply Standard CEOP8026 in March 2014 that defines the allowable range of steady state supply voltages to be 230V (-6%, +10%).

AS4777

The AS4777 defines requirements for grid connected inverters and requires that they can accommodate an operating range from 180V to 255V. The standard includes over voltage and under voltage protections associated with the extremes. The standard is included for consideration as they define the activation ranges of the Power Quality Response Modes discussed in Section 3.3.

CBEMA Power Acceptability Curve

The Computer Business Equipment Manufacturers Association (CBEMA) developed a Power Acceptability Curve in the 1970s. It is sometimes also referred to as the ITIC Curve, according to the name given by a working group of CBEMA formed by the Information Technology Industry Council in 1994, which developed it for intended application to American 120V 60Hz supply.

These curves are international standards for the acceptability of power supply to equipment and are included as a reference point to illustrate the general range of supply voltages tolerable to equipment.

The general idea behind the CBEMA/ITIC curves is that larger supply transients can be tolerated for shorter periods of time, but sustained voltage levels need to be closer to the intended nominal supply voltage.

With the increasing globalisation of the supply of consumer electrical equipment, the CBEMA values are relevant to ensure the continued performance of customer equipment. The allowable voltage range under this curve is 200V to 244V, but many customers on Australian networks received sustained supply voltages above 244V.

University of Wollongong—Long Term Study

The University of Wollongong (UOW) has been conducting a long-term study (LTS) into the Power Quality (PQ) delivered to customers in Australia. The LTS uses statistical techniques to aggregate large numbers of samples over time to provide the typical voltage range supplied to customers as a guide to network owners.

The values in Table 2 were extracted from the most recent Essential Energy submission to the Australian Energy Regulator (AER) in which they formed part of the PQ strategy documents.

The range of voltages from the UOW LTS have been included to outline the range of voltages typically provided to customers on the network sections being examined specifically as part of this report.

Summary of Allowable Ranges

Table 2 outlines the range of voltages customers would expect to see and provides some comparison with the voltage equipment it is designed to operate under, charting the ranges using a variety of sources.

	MINIMUM VOLTAGE	MAXIMUM VOLTAGE
Historic Australian Supply: 240V ±6%	226	254
AS 60038: 230V +10% / -6%	216	253
AS4777.2: Voltage range for inverter response	180	255
UOW LTS: Voltages typically supplied to customers	245	255
CBEMA: Voltages typically tolerable to equipment	200	244

Table 2 – Standard Voltage Ranges and Industry Outcomes

USING VOLTAGE TO IMPROVE DER HOSTING CAPACITY

All else being equal, a DER installation supplied with an average voltage level of 230/400V will be able to export more energy before encountering the upper allowable voltage thresholds than a DER site that has average supply voltage levels in the range 240/415 to 250/433V.

The closer the average supply voltage is to the upper allowable limit of 253V (single-phase), the less ability (DER hosting capacity) the local network will have to absorb additional DER exports.

A supply that is normally around 230V will have 23V of available headroom to absorb voltage rise caused by energy exported from DER sites before the upper limit is reached. This would be an optimal outcome.

However, a situation commonly reported in the annual national PQ studies is that a significant number of customers are supplied at voltages in the higher end of the allowable range and, certainly, significantly higher than 230V. This means that these customers have a reduced bandwidth of available room to absorb voltage rise related to DER's impact of reducing net loads. Further, DER exports will reach an upper level voltage constraint much earlier than they would otherwise if their DNSP provided supply was at 230V.

The conversion of electricity supply from the traditional 240V nominal standard voltage (240V, +6%, -6%) to the new 230V nominal (230V, +10%, -6%) has effectively only reduced the allowable upper limit voltage by one volt. This approach was implemented across Australia well before the impact of DER started to take effect on the networks, creating load destruction and voltage rise issues with export.

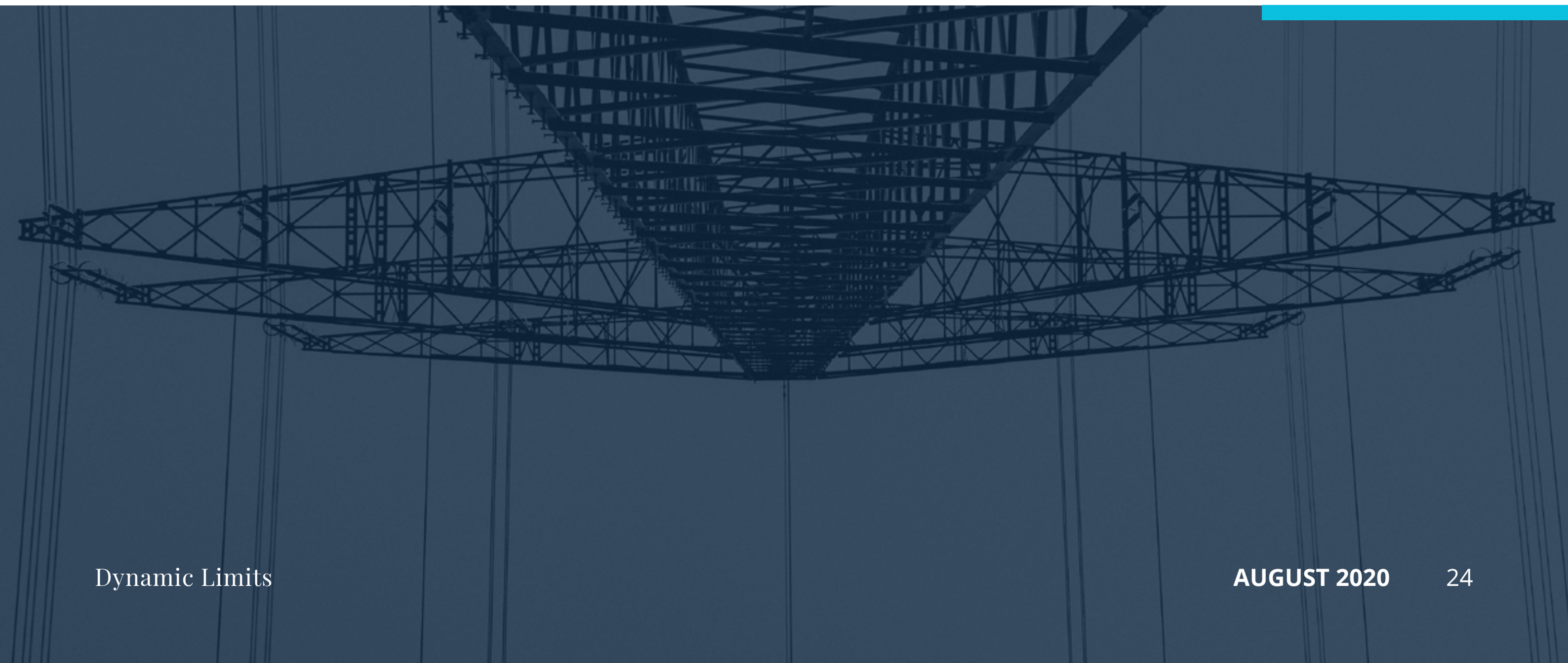
The minimal drop in upper voltage limit from 254V to 253V in moving to the new 230V nominal standard meant that DNSPs had no real need to invest in changes that would reduce voltages for those customers receiving average supply voltages higher than approximately 245V. If the allowable voltage range was implemented as 230V (+6%, -6%), as it was in New Zealand, then the upper allowable limit would have been reduced from 253V to 244V. This would also align with the upper threshold of the CBEMA curve.

The existing upper limit of 253V is usually interpreted by DNSPs to mean that they will not intervene or invest in network changes / augmentations unless the customer is experiencing voltages in excess of 253 (and typically also for more than 5% of the time). So, a customer who receives an average supply voltage around 250V would have only 3V of headroom in export before their DER installation becomes voltage constrained, but the DNSP would not be obliged to change anything to improve that. A site like this would have minimal opportunity to export.

Implementing a dynamic limit control platform in this situation will create very little new value because the unnecessarily high average supply voltage has already minimised available DER hosting capacity/headroom.

A more useful interpretation by DNSPs of the AS 60038 allowable voltage range — and one that would help to maximise DER Hosting Capacity on low voltage networks — would be still to accept the 253V as a maximum allowable supply voltage but to adopt the +6% threshold rather than the current +10% threshold as the network investment or management trigger for taking actions to reduce average voltage.

For example, many DNSPs could reduce average voltage levels either by implementing or revising tapping zone schemes in conjunction with voltage regulator operation profiles that aim at 230V nominal supply for the majority of customers, rather than 240V or higher. This is a particularly achievable outcome for DNSPs that have a high proportion of their existing installed distribution transformers that are fitted with off load tap changers.



2.3 OPERATIONAL WINDOW

Combining the thermal capacity constraint with the voltage constraints described above will provide a set of boundaries for the operation or planning of any part of an electrical distribution network.

The maximum import will be bound by the thermal capacity and the minimum voltage limit. The maximum export will be bound by the thermal capacity and the maximum voltage limit.

These could be plotted together, as shown in Figure 4, where the voltage range from AS60038 (216V – 253V) has been plotted against the thermal limits (15kVA) imposed on a single customer connection. Ideally, at any time, the conditions for the customer will lie at some point within the bounds of the square region shown in Figure 4.

However, to the extent that the average supply voltage at any installation exceeds 230V prior to any local DER generation occurring, then the DER hosting capacity on that local Low Voltage (LV) supply is being compromised from a voltage constraint perspective. The closer a low voltage supply is to the upper limit of 253V prior to DER generation commencing, the less DER generation will be accommodated prior to the upper allowable voltage limit being breached.

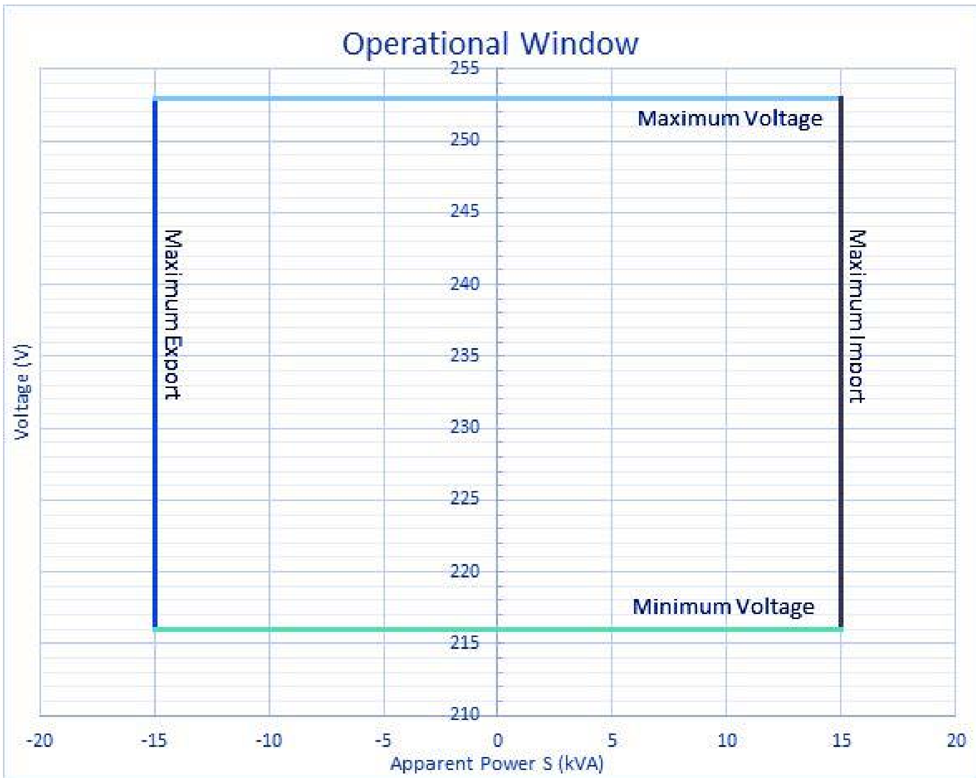


Figure 4 - Operational Window for A Single Domestic Customer

The impedance of the electrical network that supplies the customer, together with the no-load supply voltage as configured and the current net load, will dictate the point within the operational window at any time. The no-load voltage of the source supplying the customer will control the vertical position within this window.

03 EXISTING APPROACHES TO DER MANAGEMENT

This section outlines the existing approaches to DER Management on distribution networks. The use of static connection limits and network augmentation are only briefly discussed as their shortcomings are already widely established.

More attention is given to the use of Power Quality Response Modes (PQ Response Modes) under AS4777.2:2015. PQ Response Modes are a legitimate first attempt at implementing some sort of dynamic control of DER to manage local network constraints. However, the PQ Response Modes are found lacking for a number of reasons relating to their limited view of the network, recruitment and compliance issues, the voltage ranges required for activation, and the likely impact on the network.

3.1 STATIC LIMITS

To date, in response to the challenges posed by increasing DER connections and limited network DER Hosting Capacity, static capacity limits for DER have been the basic response by all DNSPs.

The application of static limits appears to be inherently conservative, in that it attempts to set a capacity limit that, under the worst-case annual conditions, will not result in network hosting capacity constraints being exceeded. The adoption of such a conservative approach then means that, for the majority of the year, the network would not be at the worst-case conditions and the static limits applying at those times would be well short of the network capabilities to host DER.

However, since every network segment has its own unique limits and DER saturation levels, it is not possible to come up with a single static limit that will be suitable to apply in all network locations. In the interests of fairness, DNSPs have historically selected a single static limit that applies to all customers in a given customer category (such as domestic supply customers) for all network areas. The only exception is that urban limits are sometimes different to limits applied to customers in rural areas. Inevitably, this means that this single, common static limit is too low for some stronger network areas, and too high for other, weaker areas.

Thus, static limits unnecessarily restrict DER installation sizes for the majority of operating hours in the year while also failing to ensure that network constraints are not exceeded in weaker areas and any network hot spots with higher DER adoption levels.

3.2 NETWORK AUGMENTATION

Traditional network augmentation has been another static approach to the management of DER. Making new CAPEX investments to strengthen networks is a valid way of increasing DER hosting capacity. However, this puts upwards pressure on network charges (and ultimately, customer electricity bills), decreases the return on assets achieved, and makes it more difficult to increase asset utilisation.

The dangers of overinvesting in network assets has been well established elsewhere. The Energy Transformation Roadmap[4] has made the benefits of effectively controlling DER to reduce network expenditure clear — the benefits amount to hundreds of billions of dollars and thus won't be re-hashed here.

However, it is clear that a better approach is needed and the industry push to move from static to dynamic controls for DER is being motivated by a desire to minimise new network capex investment and maximise Return on Assets and Asset Utilisation, as increasing penetration of DER connections and capacities occurs across the networks.

3.3 POWER QUALITY RESPONSE MODES

The Australian Standard AS4777.2:2015 Grid Connection of Energy Systems via Inverters lists a number of PQ Response Modes for inverters to enable extended and improved control. These modes are intended to contribute to maintaining power quality at the point of connection and provide some support to the grid. They represent another currently used approach to ensure that DER do not exceed network constraints. This section outlines three major shortcomings and depicts the performance of the PQ Response Modes against the operational window developed in Section 2.3.

MONITORING POINT OF CONNECTION ONLY

The first shortcoming of the PQ Response Modes is that each inverter is only factoring in the voltage on their network at their own point of connection. This means that thermal constraints at transformers are not considered at all by the Scheme. Further, by only examining their own connection point voltage, the standard opens the possibility that, even while the Scheme is being successfully implemented, there are other DER customer connection points closer to the network constraint that are well outside allowable voltage areas. This not only means that the supply standards are not being enforced effectively but that the Scheme's implementation causes inherent inequalities of network access.

[4] Available here: https://bit.ly/3f5thoR

RECRUITMENT AND COMPLIANCE

A second issue with PQ Response Modes is that DNSPs may not always have mechanisms in place to ensure that inverters with the capability to implement the standard are actually recruited to the Scheme and that those attempting to implement the standard have been configured in accordance with the DNSP's configuration requirements (which may vary from the default settings in the standard).

Stakeholder consultation revealed that only a fraction of new installations is audited and that, of those audited, only a fraction is found to be compliant.

Thus, this PQ Response Modes' effectiveness is also severely limited by the DNSP's ability to ensure that all installations able to implement the standard do so correctly.

ACTIVATION ONLY IN UPPER VOLTAGE RANGES

One further weakness of the Volt-Var and Volt-Watt responses under AS4777.2:2015 is that the prescribed (default) voltages under which the modes should activate are far too high. This relegates the Scheme to the role of a backstop that is implemented once allowable ranges are significantly exceeded, rather than something that can be used either to manage network constraints or unlock further DER hosting capacity.

Under Vol-Var/Volt-Watt responses, the inverter response is determined by the connection voltage. Table 3 outlines the connection voltage and the Volt-Watt and Volt-Var responses required. These are the default values defined in the standard, although individual inverters may have performance that exceeds these capabilities.

REFERENCE	AUSTRALIAN DEFAULT VALUE (V)	VOLT – WATT RESPONSE MAXIMUM OUTPUT POWER (P/RATED) %	VOLT – VAR RESPONSE VAR LEVEL (VAR % RATED VA)
V1	207	100%	30% leading
V2	220	100%	0%
V3	250	100%	0%
V4	265	20%	30% lagging

Table 3 – Volt Var and Volt Watt Reponses, Adapted from AS4777.2

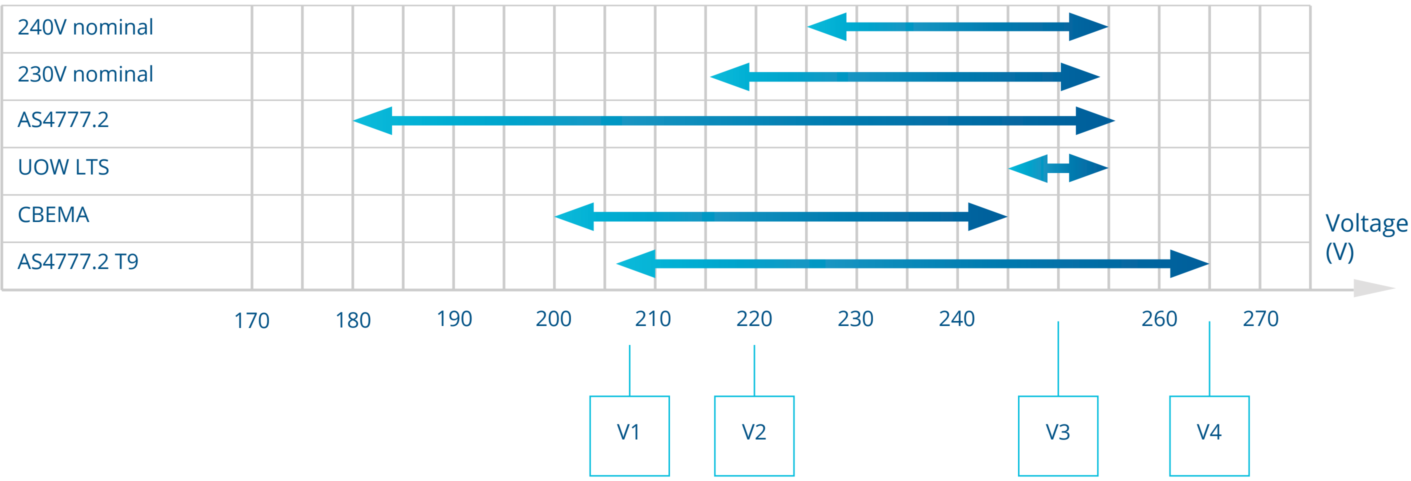


Figure 5 - Power Quality Response Modes Reference Voltages and Operational Voltages

The PQ response varies dynamically with connection point voltage in a defined way between the voltage threshold levels (V1, V2, V3, V4) which are fixed values set when the inverter is commissioned (unless the default values are to be used).

In the case of Volt-Var responses, it should be recognised that thermal limitations in the design of any inverter is typically the current switching capability of the semiconductors used to switch the output current. As a result, any inverter providing reactive current flows to the grid under a Volt-Var response will be sacrificing real power capability to supply this reactive current.

Figure 5 maps the Volt-Var or Volt-Watt response default voltage threshold levels (V1 to V4) under AS4777.2 against the voltage ranges from a variety of standards outlined earlier in Table 2. As Figure 5 illustrates, the reference voltage for PQ responses under AS4777.2 are not a good fit with the inverter operational limits or the other voltage standards in place with the majority of the response in the upper voltage range occurring outside the expected range across most standards.

Interrelationship with Supply Voltages

Many supply situations have average voltage levels in the upper range that would result in persistent curtailment of inverter output if lower set point values were adopted instead of the default values.

For the AS4777 Volt-Watt and Volt-Var responses to be most useful, average supply voltage levels will need to be lowered closer to the 230V nominal and the default set point values for the PQ Response Modes also lowered.

These combined steps will allow inverters to operate for a larger portion of time with no curtailment but will also allow useful curtailment to be applied as the voltages rise into the upper ranges.

As it currently stands, with typically high average supply voltage and the default Response Mode points set at 250V, the degree of constraint relief achieved above 250V will be minimal.

Until this is rectified, the PQ Response Modes are relegated to the role of a backstop rather than a tool that can be used either to manage network constraints or unlock further DER hosting capacity.

RESPONSES AND THE OPERATIONAL WINDOW

The Volt-Watt response of AS4777 is intended to reduce inverter output when the inverter terminal voltage is too high. This response is plotted against the operational window (for a standard 63A connection). It is apparent that, if the default settings are used, the response voltages from AS4777.2 will have minimal impact under normal operating conditions.

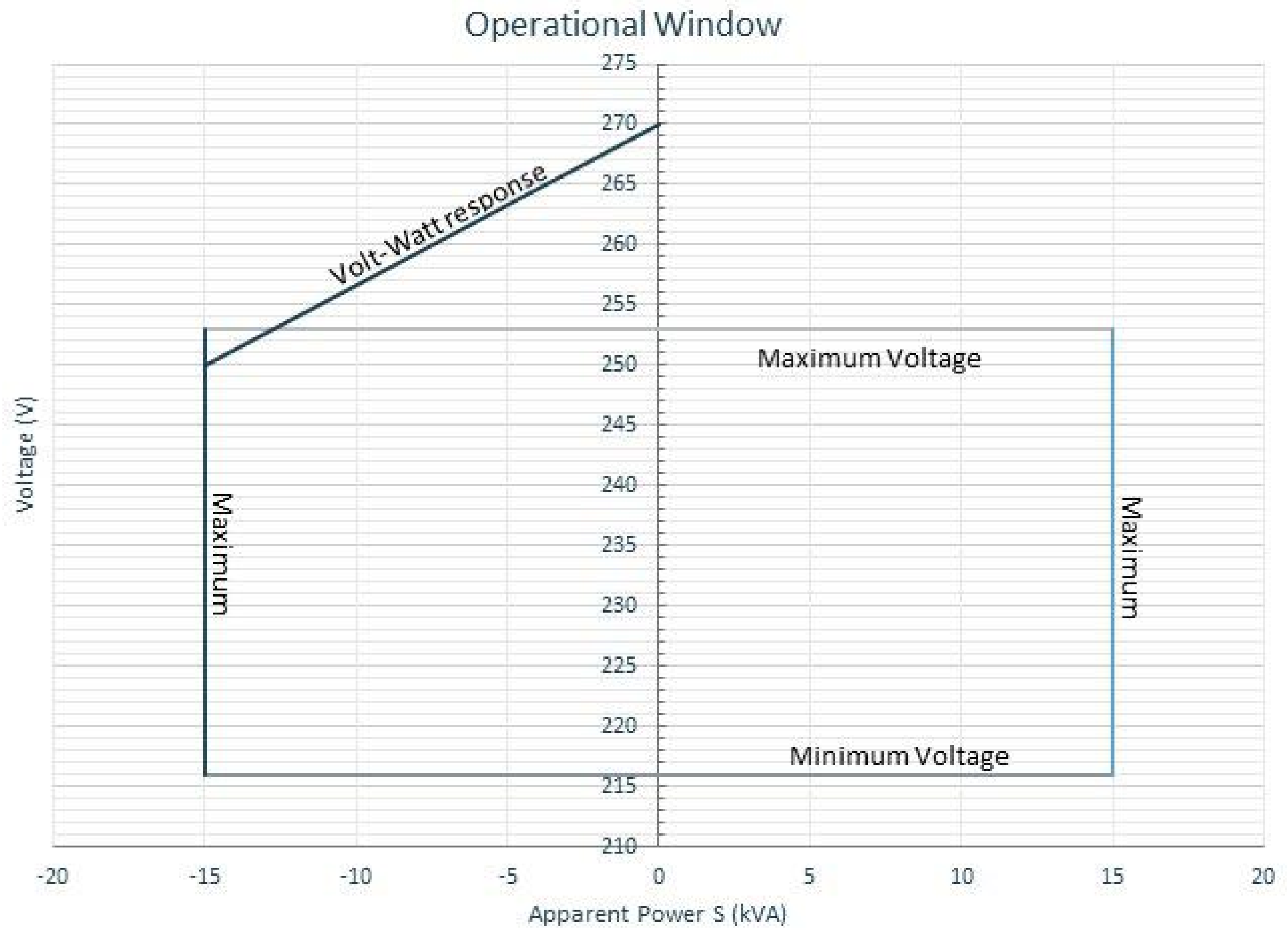


Figure 6 - Volt-watt Response Mapped against the Operational Window

Similarly, the Volt-Var response will have limited impact on maintaining operating conditions within an allowable operational window. Although the Volt-Var Response Mode is not enabled by default on inverters, it nevertheless seeks to increase the amount of leading (capacitive) reactive power generated (sourced) if the voltage falls (below 220V, default) and increase the amount of lagging (inductive) reactive power consumed (sunk) if the voltage rises (above 250V, default). That is, under high voltage conditions, the inverter is allowed to absorb up to 30% of its rating as lagging current (inductive) and, under low voltage conditions, contribute up to 30% of its rating as leading current (capacitive). This control of reactive current is common on all grid connected synchronous machines and can provide some local control of voltage.

We can estimate the approximate voltage change that can be achieved using these Volt-Var reactive flows up to 30% of the inverter rating, using an approximate rule of thumb for the operation of power systems. The rule links the local fault level to the expected change in voltage for the change in reactive power and is the most accurate when the network source resistance is very small and the network inductive impedance is very much larger than the resistance component. The rule becomes less accurate on long, weak feeders where the resistive component of total network impedance can become more significant, but the insight generally provided by the rule is still useful:

This approximate voltage change can be represented by:

$$\Delta V = \frac{kVAr}{kVAsc} \times 100\ (\%)$$

ΔV=change in voltage in %

kVAr=reactive power change in kVAr

kVAsc=local short circuit fault level in kVA

Equation 1 – Relationship between Voltage, Reactive Power, and Short Circuit Fault Level

For example, the lowest fault level in the Brimbin group of houses (examined later in Section 10.1) at the point of connection is 440kVA. Assuming there is a single inverter in this group of houses utilising the entire thermal capacity of the transformer, the maximum inverter power would be 25kVA/3 = 8.3kVA; 30% of this capacity is the maximum reactive power swing allowed in the AS4777.2 PQ Response Modes, giving an expected change in reactive power of 2.49kVAr. Using Equation 1, the expected voltage change would be 2.49/440 x 100 or 0.57%. On a nominal 230V system, this would equate to 1.3V. As this example illustrates, it is unlikely the Volt-Var scheme as described in the standard would have a material impact on the voltage performance of the customer installation.

The Volt-Var scheme will have a greater impact where the fault level is lower because smaller curtailment amounts will have a larger corrective action (and smaller loads and generation amounts will be more disruptive). The fault level at a low voltage customer connection is dominated firstly by the distribution transformer impedance and then much more so by the low voltage mains and service wire impedances. The scheme will, therefore, have a bigger impact with smaller transformers, longer LV supply route lengths, and smaller supply conductors at LV (but in these situations the ‘rule of thumb’ described above will be less accurate due to the increasing relevance of network resistance compared to network reactance). This may raise issues of curtailment fairness where customers are treated differently depending on the structure of the network supplying their point of connection.

In the weakest and most remote parts of rural networks and particularly on very long SWER lines, the resistive component of total network impedance can become so significant that injections of real power become more effective.

SUMMARY

The examination of PQ Response Modes — including Volt-Var and Volt-Watt responses — undertaken in this section finds that for several reasons the PQ Response Modes will not contribute meaningfully to increasing DER hosting capacity.

First, the responses only consider the voltage at the point of connection (and are thus blind to network operating conditions at the local constraint location). Further the response cannot contribute to thermal constraints.

Second, recruitment into the Scheme is optional, and compliance of participating inverters is not ensured.

Finally, the Scheme's default settings provide negligible curtailment for connection voltages in the upper range.

The Response Modes will assist to limit excessive voltage rise within installations above the maximum allowable threshold prior to over-voltage protections being triggered, but overall they will not be a viable or adequate mechanism for unlocking the DER hosting capacity of networks or ensuring that network constraints are not exceeded.

04
GENERAL BENEFITS OF DYNAMIC DER CONTROL

The idea of varying DER limits dynamically, rather than imposing a single static limit, makes sense intuitively. At times when the network has increased hosting capacity headroom, the curtailment limits on DER capacities could be relaxed, and vice versa. This concept suggests that the installed capacity of DER sites could be larger because their outputs would be reduced when necessary.

This principle occurs every day in a range of other systems that experience fluctuating demand. For example, traffic slows down on highways as congestion increases, and internet service providers throttle back our download speeds during periods when user demand climbs on their networks.

This section quantifies the benefits that dynamic control of DER export limits can deliver in terms of increases in network hosting capacity. Modelling is carried out for a typical rural supply scenario involving a group of four cottages supplied by a shared, thermally-constrained, 25kVA transformer and reveals that the DER installation could be tripled in size while only requiring curtailment of approximately 12% of the potential annual energy output. These findings are later confirmed in the site-specific modelling undertaken in Section 10

4.1 APPROACH

In this section, we summarise a modelling outcome arising from considering hour-by-hour cumulative duration and frequency distribution curves of a typical annual solar irradiance profile overlaid on a typical residential 24hour load profile, with the modelled site supplied through a simple model of network impedance arranged to deliver a voltage constraint rather than a thermal constraint. This is a typical scenario in rural electricity networks.

The approach uses a simple network model of a typical rural domestic supply to an installation that features a typical annual hourly domestic load pattern and is fitted with a photovoltaic (PV) array at various sizes (5, 10, 15, 20kW). This is then overlaid with a typical hourly insolation profile for a whole year. We plotted the responses possible when the PV output was curtailed as necessary to keep the total supply within the voltage or thermal constraints.

In this calculation, the local connection point voltage of the DER installation was used as the Scheme control voltage; however, voltages at other network locations could also be used for this purpose.

Normal system voltage was set at 1.02pu (234.6V and 11.22kV) and the maximum voltage at the constraint control point was set at 1.07pu (246.1V and 11.77kV). These voltages were chosen to keep the customer voltages well within the upper and lower bounds of the licence conditions and to show that significant increases in hosting capacity are achievable without using the highest 3% of the allowable voltage range, provided the normal system voltage is closer to 230V.

The maximum solar generation was based on real-time hourly solar data for the general location over a five-year period and assumes no shading, panel thermal effects, or inverter losses.

The customer load cycle was based on a family home with electric heating, cooking, cooling, and a swimming pool. The approach could be repeated for other customer load profiles and network impedances (where known). It could also form the basis of some automated projection, checking, or optimisation of proposed operating profiles at a given site where those additional customer load and network impedance details are known or where there is a significant DER installation justifying special assessment.

4.2 RESULTS

When dynamic localised control of the inverter is applied, scaling back the inverter input as the local control voltage approaches the limit point, a higher total annual solar yield from the inverter can be realised without exceeding the local voltage constraint.

Currently this graduated curtailment does not happen, and the inverter over-voltage protection mechanism imposes a hard limit if the threshold voltage is triggered. The inverter must then cycle through a delay period where it confirms the local supply has returned within acceptable bounds for a minimum period of time prior attempting to reconnect. After successfully reconnecting, if ample solar input still exists the inverter could again contribute to recreating the over-voltage condition again, risking subsequent repeated disconnections.

The results of the modelling of the various inverter sizes over a typical rural domestic customer with a low capacity, shared low voltage supply are outlined in Table 4. The table displays the maximum generation and amount of necessary curtailment across a number of inverter sizes.

INSTALLED SYSTEM SIZE	MAXIMUM SOLAR GENERATION PER ANNUM (KWH)	% CONSTRAINED OPERATION (>1.07PU)	ENERGY LOST DUE TO CONSTRAINT (KWH)	ENERGY WITH DYNAMIC LIMITS FROM SOLAR (KWH)
5kW	9, 210	0	0	9, 210
10kW	18, 420	0	0	18, 420
15kW	27, 631	440	3, 362	24, 269
20kW	36, 841	2566	9, 412	27, 429

Table 4 - Comparison of Required Curtailment across Various System Sizes in a Typical Rural Network Scenario

Although increasing the inverter size does not initially lead to curtailment, there is a point of diminishing economic returns as the inverter size grows too large for the location. This can be seen in the case of the 20kW system connected to the model, where the amount of energy curtailed by the dynamic limits scheme starts to grow excessively compared to the 5kW, 10kW, and 15kW inverter scenarios.

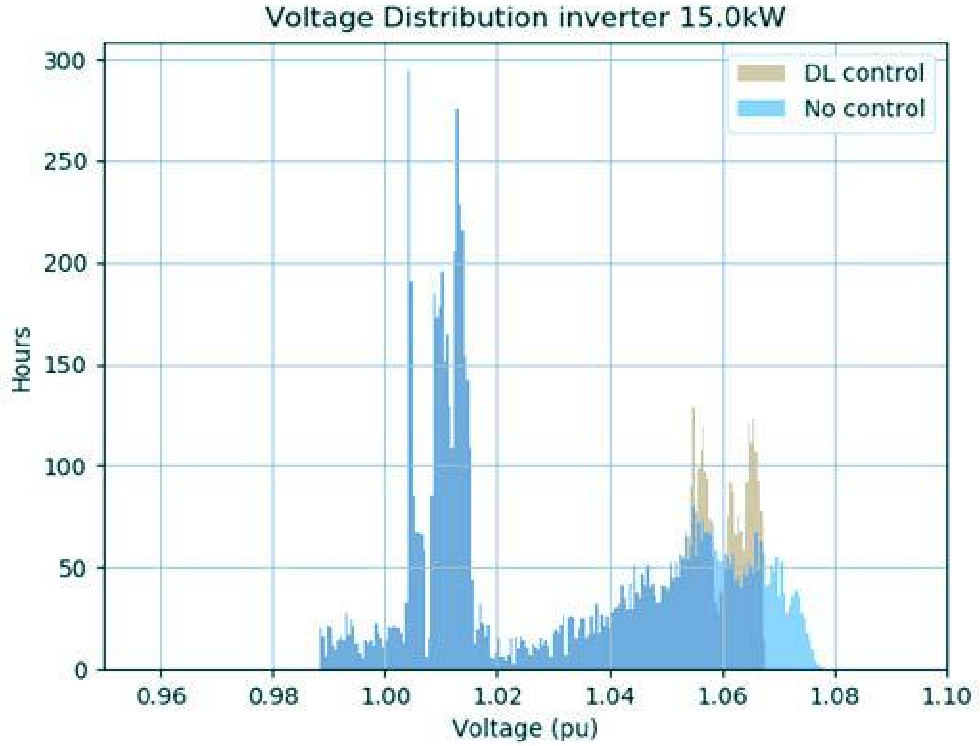


Figure 7 - Voltage histogram, comparing constrained operation with unconstrained operation

That aside, with the dynamic curtailment control applied, connection of this largest (20kW) inverter is not precluded because the network operating conditions remain within the standard voltage ranges.

The impact of this control over the voltage can be seen in Figure 7, which compares the histograms of the customer voltage between constrained and non-constrained operation of the a 15kw solar system.

Overall, this model shows that the use of dynamic control over DER to ensure local network voltage constraint is not exceeded can accommodate DER installations three times larger while only reducing output approximately 12% from a theoretical maximum and keeping within the local network voltage constraint at all times. This leads to a 160% increase above the energy yield achieved from the 5kW baseline scenario.

Whilst this modelling only considers one supply scenario, it provides an indication of the ability of dynamic control of DER to increase the hosting capacity of networks.

05
OTHER INITIATIVES

This section outlines other major initiatives that seek to dynamic management of DER.

The previous sections examined existing approaches to managing DER on electricity networks (Section 3) and established the general benefits of managing DER dynamically (Section 4).

This section outlines some of the work undertaken as part of the OpEN Initiative, which is led by Energy Networks Australia (ENA) and AEMO and briefly outlines the work undertaken as part of the development of the IEEE 2030 Standard. This is done to provide context for subsequent sections that examine the principles applied in developing the DDL Control Scheme (Section 6) and describe the DDL Control Scheme in detail (Section 7).

The OpEN Initiative examines and defines the possible roles, platforms, frameworks, and models for the dynamic control of DER targeting of both DER Orchestration Tasks and DER Control for Local Network Constraint Management.

The OpEN Initiative's focus on the potential role of DSOs and the models or frameworks under which such a new actor may be introduced into the energy system are not examined as part of this report, other than to make the observation that the role of decentralised control for managing dynamic limits for DER inside local network constraints has not been anticipated in these models or frameworks.

Rather, this section reviews a number of major reports commissioned as part of the Initiative. First, we review the challenges identified in these documents that any scheme implementing dynamic DER operating envelopes must address. We then review principles identified by the initiative that may overcome these challenges. The vocabulary used by the Initiative to describe different functions, tasks, and processes is also outlined to help provide additional context to the DDL Control Scheme. Finally, the next steps for the Initiative are reviewed as these may also outline a potential path to implementation for the DDL Control Scheme.

This section provides some background on the Initiative before then reviewing each of the three reports published as part of the OpEN Initiative. The Section concludes with a brief outline of some of the work undertaken as part of the IEEE Smart Grid Interoperability Standard.

5.1 BACKGROUND

ENA and AEMO's OpEN Initiative has its roots in the development of an Electricity Network Transformation Roadmap[5]. A key output of that study was that the potential benefits of properly utilising DER were quantified for the first time. According to the report, more than $16 billion in deferred network expenditure would be potentially achievable through proper integration of DER. The study also made clear the cost of inaction — for customers, network charges would be 30% higher in a 'business as usual' scenario.

Building on this, the OpEN Initiative attempts to determine how best to transition to a two-way grid that allows better integration of DER to deliver better outcomes for all customers. The project investigates "market and network frameworks that can facilitate market access for all stakeholders (DER owners, aggregators, network operators, etc.) while ensuring that technical network limits are not breached and the integrity and security of the network is preserved, maintaining a safe and reliable power supply for all."[6]

The OpEN project underwent an extensive consultation process and has released a number of interim reports covering different aspects of the transition. For the DDL Scheme project, however, there are three key reports that are relevant for brief review here — an international review conducted by the Newport Consortium (the Newport Review), an investigation of the high-level functionality required to implement DER Optimisation by EA Technology (the EA Technology Report), and OpEN's "Interim Report — Required Capabilities and Recommended Actions".

5.2 NEWPORT REVIEW

The international review conducted by the Newport Consortium entitled "Coordination of Distribution Resources: International System Architecture Insights for Future Markets Design"[7] was commissioned by AEMO and ENA as part of the Open Energy Networks process to contribute to understanding international approaches and models for addressing the system architecture and defining the roles, responsibilities, and control coordination for real time operation of DER. While making a number of recommendations, the most relevant contribution for this project is that 'layered decomposition' and the use of a 'hierarchical control structures' may solve a range of challenges that the integration of DER into the power system of the future presents.

5 ENA & CSIRO, 2017, Electricity Network Transformation Roadmap, available here: https://bit.ly/3f5thoR
6 EA Technology Report, p.4, available here: https://bit.ly/2VPTzlZ
Specifically, four frameworks were investigated: A Single Integrated Platform, Two Step Tiered Platform, Independent Distribution System Operator, and a Hybrid Model. For an overview of these, refer to the above report.
7 The entire report is available here: https://bit.ly/3auvS88

CHALLENGES

The Newport Consortium outlines a number of obstacles the future smart grids must overcome and avoid. These include Tier Bypassing, Hidden Coupling, and Latency Cascading.

Tier Bypassing describes a problem where information flows or control instructions skip tiers or layers of the power system and thus opens the possibility for operational problems to be created.

Hidden Coupling is another, similar problem. The term describes the phenomena where two or more control schemes have partial views of the entire grid state and are operating according to individual goals and constraints. Problems will arise when these goals or constraints are in conflict.

The following example illustrates the concepts of Hidden Coupling and Tier Bypassing.

A wholesale market event, such as a price spike, may trigger a response from DER, such as the orchestrated export of energy. This, in turn, may then cause a local network constraint, such as an upstream transformer approaching its thermal limit in export. A DNSP may then dispatch DER to sink real power in response to this constraint via another energy aggregator.

If the DNSP is unaware of the wholesale market event or the energy aggregator is unaware of their effect on the network because this information isn't shared across all tiers in the control hierarchy, then Tier Bypassing has occurred.

The fact that the two actors (the DNSP and aggregator) now have competing agendas as a result of the partial knowledge constitutes Hidden Coupling.

Latency Cascading is another problem the report recognises. The term describes the creation of excessive latencies that will arise if information flows are directed serially through cascades of different organisations and their systems, with each step adding to the total delay time.

LAYERED DECOMPOSITION & HIERARCHICAL CONTROLS

According to the report, there is international recognition that Layered Decomposition may solve a range of other problems that smart grid architecture may encounter.

The report adopts the principle of Layered Decomposition from optimal control theory. The idea of Layered Decomposition is that large-scale optimisation problems can be solved by decomposing the problem into sub-problem solutions that work in combination to solve the original, larger problem.

The report states that applying the principle of Layered Decomposition is also able to contribute to understanding the observability requirements of the network. Observability, in this context, refers to the level of sensing and data collection required to enable an adequate view of the system so that "system control" can be appropriately implemented (in the most general sense of that term).

The report uses the example of implementing Hierarchical Control structures to outline the point. Primary (or higher level) controllers communicate with secondary or lower level controllers. These lower level controllers examining the current grid state can implement fast control loops while providing slower control loops back to high level controllers.

According to the report, the use of Layered Decomposition and Hierarchical Control structures has received "growing international recognition"[8] as a way to overcome potential problems including Tier Bypassing, Hidden Coupling, and Latency Cascading.

5.3 EA TECHNOLOGY REPORT

The EA Technology Report was commissioned to understand the functionality required for each of proposed smart grid models investigated as part of the OpEN project. The report makes two contributions relevant to this project — a description of the functions and activities associated with DER Optimisation and the provision of a framework for outlining the capabilities required for optimising DER on distribution networks.

DER OPTIMISATION FUNCTIONS AND ACTIVITIES

The EA Technology Report builds on the work of the OpEN project to contribute to the development and clear definition of DER Optimisation functions and tasks, which is central to the current investigation of the DDL Control Scheme.

The detailed description of each function (covered at length in Appendix I of the report) makes it clear that this project is focused exclusively on Function 6: DER optimisation at the distribution network level.

According to the report, this function should "optimise operating envelopes to ensure aggregated bid stacks for DER per area can feed into wholesale optimisation taking account of distribution network constraints."[9]

Two activities are then described to achieve this function: optimising operating envelopes given constraints and aggregating the various DER bids.

The optimisation of operating envelopes is described as the requirement to "provide distribution network end-customers with optimised operating envelopes taking account of distribution network constraints."[10] This activity sits at the centre of the DDL Control Scheme being investigated as part of the current report. Our use of the term DER Control for Local Network Constraint Management describes this task.

The second activity, the aggregation of bids, is described as the requirement to "Submit aggregated bid stacks

8 This is part of the second key finding of the report, outlined on Page 15 and elsewhere in the report.
9 Page 107 of the report, and elsewhere.
10 As above

for DER per area that can feed into wholesale optimisation within distribution network operating envelopes."

This second activity is beyond the scope of the current project. However, should the project demonstrate that the proposed control scheme is effective for achieving the first task, a logical next step is to explore how this second activity could also be accommodated under the Scheme.

REQUIRED CAPABILITIES FOR DER OPTIMISATION

The EA Technology Report also outlines three required capabilities and enabling actions needed to achieve the task of DER Optimisation on distribution networks.

These capabilities follow a logical sequence of determining network constraints, defining operating envelopes, and communicating the operating envelopes. There a number of actions that are undertaken to achieve each of these, which are outlined in Figure 8 (adapted from the EA Technology Report, p.6).

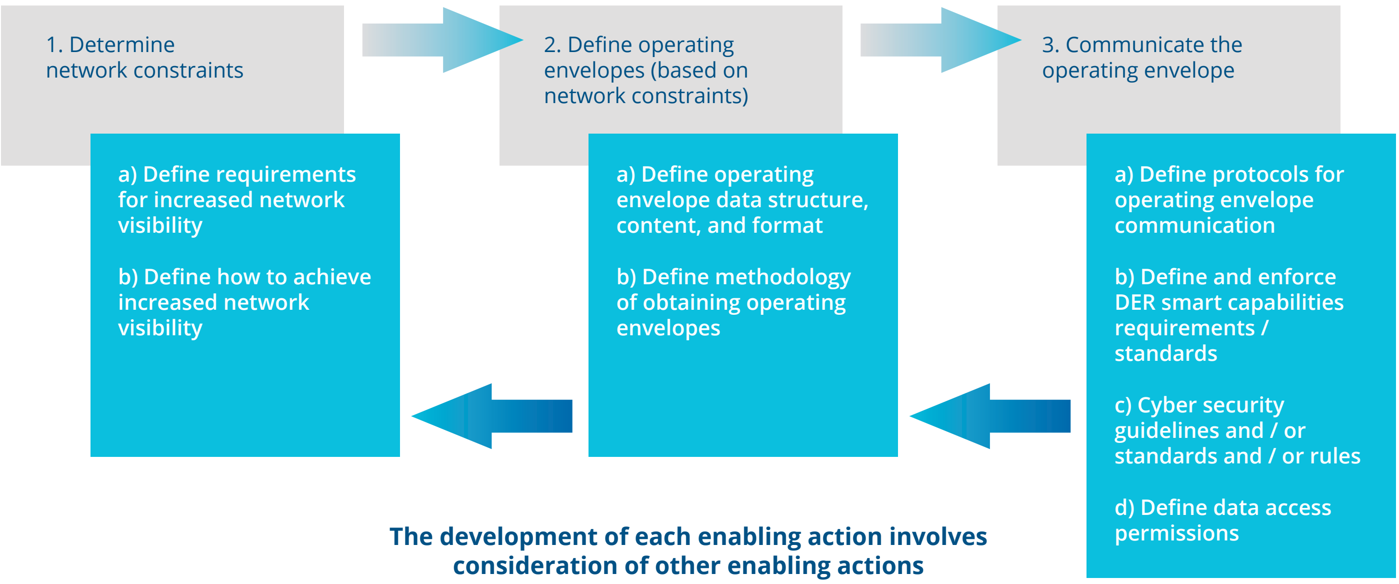


Figure 8 - Capabilities and Enabling Actions for Improving DER Integration

The framework depicted in Figure 8 provides a simple but effective way to outline and understand the key tasks that the DDL Control scheme must achieve.

This framework of actions and capabilities is later used to outline the potential implementation of the DDL Control Scheme (in Section 7.5)

5.4 INTERIM FINAL REPORT

The OpEN's Interim Final Report[11] details both the proposed models for the implementation of a Distribution System Operator (not covered here) and a set of "least regret" capabilities and milestones that can be achieved irrespective of the DSO model pursued.

The milestones include defining network visibility requirements and network constraints, defining the requirements for communicating operating envelopes for DER, and establishing a guideline for operating envelopes and export limits. The milestones and capabilities required are shown in Figure 9.

MILESTONE 1

DNSPs defining network visibility requirements and network export constraints

- Define DNSP requirements for increased network visibility to maintain network operations within required parameters
- Define how to achieve increased network visibility to maintain network operations within required parameters (operating envelopes)
- Establish an iterative and targeted approach for the timing of investments required to provide network visibility to maintain network operations within required parameters

MILESTONE 2

Defining communication requirements for operating envelopes

- Define protocols for operating envelope communication
- Establish Australian standards and / or guidelines to support the establishment of operating envelopes
- Define data access permissions

MILESTONE 3

Establishing an industry guideline for operating envelopes for export limits

- Develop an industry guideline that outlines the requirements and use of operating envelopes

Figure 9 - Required Capabilities and Milestones for the Open Energy Networks Project

This project contributes to the tasks listed under Milestone 1: defining network visibility requirements and how to achieve them to ensure that the network operations are within the required parameters. However, the overview specification of the DDL Scheme also describes the communication requirement for the operating envelopes and proposes specific approaches to create operating envelopes for (import and) export limits that honour local network constraints. The framework also provides a set of logical next steps for this project (as outlined in Section 11).

11 The full report is available here: https://bit.ly/35oqDWy

5.5 OTHER INTERNATIONAL STANDARDS AND INITIATIVES

A further major international initiative has been the development of the IEEE 2030 series of standards for Smart Grid Interoperability, and the associated documentation that has been published as part of the development of that standard.

Careful consideration of IEEE 2030 and in particular, how the proposed DDL Scheme may map onto the comprehensive Smart Grid Interoperability Reference Model (SGIRM) from IEEE2030-2011 is beyond the scope of this report. However, we note our preliminary assessment that the DDL Scheme can be mapped onto the SGIRM framework (domains and entities) provided some new interfaces are introduced.

For example, the SGIRM does not appear to anticipate network visibility data flows that go directly from network sensors to local DER controllers via a data exchange service. Also, the SGIRM does not anticipate operating envelopes for local network constraints that can be assigned in full ahead of time and then managed by a local controller in near real time. Further, the SGIRM does not foresee this occurring without the intermediate processing of the data to create the DER operating envelopes and commands by the System Control and Energy Services domains defined in SGIRM.

Our current position on this mapping of the DDL Scheme to the SGIRM is that whilst this model does not appear to have anticipated decentralised control approaches for management of DER inside local network constraints, in itself this does not mean that the DDL Scheme is invalid or unworkable.

In addition to the 2030 series of standards, the IEEE Standards Association also published the IEEE Vision for Smart Grid Controls: 2030 and Beyond. This report raised some important points that are relevant for the current project. These include the anticipation of future use of intelligent end point controls and smart periphery (capable of enacting the faster inner control loops outlined in Newport Review — see Section 5.2.2). This is a parallel theme to the Newport Review's emphasis on Hierarchical Control and Layered Decomposition.

The IEEE Vision to 2030 also outlined how smart grid solutions should expect to be heterogeneous, as different subsystems with different constraints that face different challenges will benefit from different control approaches.

The DDL Control Scheme described later in this report has not been generally anticipated in the IEEE 2030:2011 SGIRM model or the OpEN frameworks. However, it has been developed with these industry initiatives in mind, albeit with a particular focus on the challenges of simple, low revenue, rural, and remote networks. The control approach described is thus an example of the application of intelligent end point control and smart periphery, as well as the heterogeneity of solutions that the IEEE initiative foresees to address the different grid subsystems and the specific challenges they encounter.

5.6 SUMMARY

The overview of key industry documents and working group outcomes provided in this section has confirmed a number of requirements and expectations relating to dynamic DER control and future Smart Grid control generally, and the relevance of the DDL Control Scheme proposed in this report.

These include the importance of Layered Decomposition (discussed in 6.2 as "Subsidiarity") and Hierarchical Controls (with the DDL Control Scheme of this report being a lowest level control platform with interfaces to all higher levels).

The functions highlighted by the ENA framework also provide a useful framework for describing the functionality of the DDL Control Scheme.

Further, the DDL Control Scheme, as described in Section 7, addresses issues of Latency Cascading, Tier Bypassing, and Hidden Coupling in a unique fashion, as outlined in Section 8.

06
DECENTRALISED CONTROL FOR NETWORK CONSTRAINT MANAGEMENT

This section builds on the preceding discussion by outlining the five key principles of the hypothesis that decentralised control of DER for the management of local network constraints can provide a range of benefits and that these are particularly pronounced for rural and remote networks.

6.1 MANAGEMENT OF LOCAL NETWORK CONSTRAINTS AS THE PRIMARY CONTROL FUNCTION

This report uses the terms of DER Control for Local Network Constraint Management and DER Orchestration to describe different but potentially competing tasks (See the Glossary and Section 1.3 for their definitions).

This project's first guiding principle is that DER Control for Local Network Constraint Management has priority over any DER Orchestration task and should be the primary objective of any scheme for implementing dynamic operating envelopes.

This means that, if Hidden Coupling were to occur and the DER Orchestration agendas and DER Control for Local Network Constraint Management DER Management are in conflict, the DER Management agenda should always prevail.

The basis for taking this approach is that there are generally no central or higher level DER control objectives that justify DER installations being operated in a manner that causes local network constraints to be exceeded.

System Security as a Special Case

There may be other agendas that also temporarily take primacy in DER control priorities. System security is one such example. In instances such as this, network constraints may be able to be temporarily exceeded — for example, the thermal time constants of typical oil-filled transformers may allow us to temporarily exceed the thermal rating of these devices in a managed way when justified by special circumstances to allow greater DER export.

However, even in these scenarios, network constraints must be managed.

For example, the over current rating of transformers cannot be exceeded indefinitely without consequence. Another example might be that a generic conductor rating of an overhead line may be increased in a situation where local visibility of ambient temperature, insolation, and wind speed at the line constraint location allows us to be confident in using a higher rating limit temporarily for that situation.

This means that, even in scenarios where system security requires constraints be temporarily exceeded, network constraint management remains the primary control task. This is because the consequences of exceeding limits for longer periods will usually have poor outcomes. These include damaging equipment or causing problems at customer premises as well as catastrophic consequences, such as an overloaded line on a hot day sagging excessively and causing contact with vehicles or worse; or failing completely and falling energised to the ground, creating serious risks such as starting bushfires or dangerous electrical hazards.

Ensuring that network constraint management is the primary objective for the Control Scheme means that other secondary objectives relating to DER Orchestration can be enabled and undertaken without putting equipment or safety at risk.

6.2 SUBSIDIARITY

The second principle applied in the development of the DDL Control Scheme is Subsidiarity. This principle states that the most efficient and effective outcomes will be achieved when decisions are made at the lowest level possible of a hierarchy. The principle of Subsidiarity applies equally well to control systems as it does to organisations or other hierarchical structures.

The principle of Subsidiarity is related to the principles of Hierarchical Control and Layered Decomposition outlined in the Newport Review and Section 5.2 of this report.

The principle of Subsidiarity extends these principles to state that control problems that arise at lower levels in a control hierarchy will be most effectively solved (to use the language of Layered Decomposition) with decentralised control. (See Sections 1.3.2 and 1.3.3 for a definition and discussion of lower and higher level control problems and centralised and decentralised control solutions.)

The project has applied the principle of Subsidiarity in recognition of the challenges that it can overcome. The project also anticipates that this principle will prove particularly effective when addressing the challenges of implementing fast, autonomous, reliable, and dynamic DER controls to manage local network constraints over vast, sprawling, rural, and remote distribution networks.

6.3 EMPOWER CUSTOMER CHOICE

A further principle incorporated into the Scheme is that it must, where possible, empower and extend the energy choices of DER customers, enabling them to make informed choices about their retailers, tariff structure, desired DER functionalities, and opportunities to participate in DER Orchestration schemes and in what order of priority.

This project is of the view that any scheme seeking to implement a DER Orchestration agenda will likely also benefit from some form of intelligent local control because the existence of a programmable and configurable local controller will allow more sophistication and customisation in the way that DER customers can participate in these various schemes.

Such a controller must adequately respond to customer expectations around the configurability of their energy choices and priorities. This may include, for example, how to apply consumer preferences with respect to self-consumption, participation in the provision of network services (potentially lowering costs for everyone in your DNSP area), aggregation schemes (lowering wholesale costs), or peer to peer trading (and potentially "donating" energy to local organisations such as schools).

Further, the project is of the view that any control scheme for managing and optimising DER should facilitate competition among energy service providers rather than present an opportunity for retailers, networks, aggregators, or other third parties to lock consumers into a specific technology or vendor for DER Orchestration activities.

Creating standards and functional specifications that are either Open Source and/or facilitate switching between energy aggregators or other actors implementing DER Orchestration Agendas is likely the best way to achieve this.

6.4 HETEROGENEITY OF SOLUTIONS

The project also recognises — as outlined in the work undertaken as part of the IEEE 2030 standard (See Section 5.5) — that there will likely be a heterogeneous range of technology solutions operating in the smart grid of the future.

For this reason, any scheme must be able to integrate with a range of other technologies and platforms from a range of current and emerging stakeholders.

The range of solutions that are required to operate cohesively together includes solutions for implementing or contributing to different tasks, such as DER Management, DER Optimisation, and DER Orchestration (as outlined in Section 1.3.1). It is anticipated that some of these tasks will occur across different layers of the control hierarchy (See Section 5.2.2) and that some tasks will be served best by occurring with greater or lesser degrees of centralised and decentralised solutions.

Interoperability will be required with the systems of a range of different stakeholders, some existing (like DNSPs and AEMO) and others emerging (like DSOs and energy aggregators) across the entire spectrum of the control hierarchy.

The report's hypothesis remains: the decentralised control of DER for the management of local network constraints can provide a range of benefits, in particular for rural and remote networks. However, acknowledging the heterogeneity of likely solutions requires that any solution for DER Management have interoperability as a key priority.

6.5 THE SPECIFIC CHALLENGES OF RURAL AND REGIONAL NETWORKS

Rural and remote distribution networks have some key differences to dense urban networks. They feature higher network asset counts (e.g. km of line, distribution transformer count) per customer connection and per unit of load served. Their network footprint area is usually only partially served by communication networks. And they have lower revenue per km of line available to manage these challenges.

These differences are at the centre of the hypothesis that a control approach using distributed control will better achieve the outcomes of local network constraint management while increasing DER hosting capacity for such networks.

NETWORK STRUCTURE

Rural and remote electricity networks are lightly built. Most commonly, they are voltage constrained on the long line segments and thermally constrained at power equipment such as transformers, regulators, and zone substations (although thermal constraints on cable and line sections do also sometimes occur). Further, the number of instances and locations where network constraints occur is in proportion to the higher number of substations and network segments, both of which are high relative to those experienced by their urban counterparts and the load the network serves.

The revenue of these networks per km managed is also low by urban standards. This may make it difficult to justify the costly production of extensive network models required in some approaches to network visibility and constraint management.

The weakest, longest, lowest revenue, rural, and remote network kilometres in Australia also cover the greatest sunshine collection area of all networks. While DER capacities in these rural and remote network areas might be small compared to the significant or large DER installations connected at other locations, they are often not small relative to the capacity of the weak rural networks to which they are connected.

Further, networks usually strive to ensure that all customers have equal access as far as possible to the installation of solar (and other DER) and the benefits from participation in DER Orchestration schemes. However, the inherent variability of network capacity due to location, network construction, distance, capacity, load growth, and many other factors makes this challenging. Further, these problematic differences between network capacities available to customers in different locations are generally the greatest in rural networks.

Given the large solar access area encompassed by these weak rural networks, it is essential that an effective DER control platform is used to manage local network constraints. The DDL Control Scheme was specifically developed with the intent of facilitating the dynamic management of DER capacities in rural and remote areas while also avoiding the expense of providing and maintaining accurate network models (and the control uncertainty of relying on network models for this purpose).

MANAGING WITH POOR COMMUNICATIONS COVERAGE

A further principle applied in the development of the DDL Control Scheme is recognition that it must operate effectively despite the poor communication coverage that rural and remote networks face. It is common for rural and remote network networks to have customers in areas where communications are unavailable or unreliable.

With this in mind, an objective of the DDL Control Scheme was to develop the ability of the DER controls to continue working intelligently — and preferably with some dynamic capability — even when communication channels became compromised or unavailable for periods of time. Last Mile functionality options were also considered important and included in the DDL Control Scheme specifications.

07
DDL CONTROL SCHEME OVERVIEW

Previous sections have provided context for the principles that have guided the DDL Control Scheme. This Section describes the four key elements to the DER control scheme—Network Sensors, the Open Network Data Platform (ONDP), DER Controllers, and the Dynamic Limits Profiles (DLP). This section provides more information on each aspect before giving an overview of the Scheme's operation by applying the framework developed and outlined in Section 5.3.2.

7.1 NETWORK SENSOR

The implementation of the DDL Control Scheme involves the use of network sensors to measure the point of constraint. The network sensors are intelligent edge-controllers operating on an Industrial Internet of Things (IIoT) platform, which will measure the actual operating status of a network constraint location. The sensors may measure thermal constraints (current) on up-stream network assets, or voltage constraints (either upstream or end of line), or both.

These network sensors are robust, outdoor-rated devices with adequate insulation and over-current protection for direct installation on networks.

The intelligent controller enables the sampling frequencies and formats of the data collected to be customised and pre-processed prior to publication. Calculations can also be done locally, such as the use of mathematical models to create net load forecasts for the constraint over a specific period.

Different subscribers can thus request different data sets optimised to their purposes. Data is only sent (published) once to the ONDP, which then distributes the data to all authorised subscribers of that specific data stream (see Section 7.2). Further, the data set characteristics and optimisations can be changed at any time via over-the-air updates.

However, the use of a network sensor requires that network planners are able to identify the network constraints in advance. On simple, mostly radial, manually switched rural networks, this is a relatively straightforward task, further underscoring the relevance of the DDL Control Scheme to these networks.

The use of network sensors rather than network models and constraint engines is a key point of difference from other approaches to managing DER integration.

7.2 OPEN NETWORK DATA PLATFORM

The DDL Control Scheme requires the use of an ONDP, which serves two functions. The first is to collect and store network sensor data and securely send this to authorised data subscribers. The second function is to enable DNSPs/DSOs to manage and administer the DER Controllers and Network Sensors and review the data they generate.

AUTHORISATION AND DATA EXCHANGE FUNCTION

A primary function of the ONDP is to facilitate the secure, controlled, and authorised parallel and fair access to lowest-latency, near-real-time, network data coming from Network Sensors located at the pre-identified network constraint locations relevant to each DER installation.

Closed data platforms (where the only subscriber to a network sensor is the company that installed it) are problematic. They negatively affect competition and efficiency in the provision of network services by increasing transaction costs, can create the need to duplicate infrastructure, and contribute to Latency Cascading (as outlined in Section 5.2.1). Overall, closed data platforms transmitting data serially will inhibit energy innovation.

The ONDP facilitates communication via a data broker using a point-to-multipoint protocol. This sends data from the Network Sensors (and, potentially, the DER Controllers) to all authorised subscribers simultaneously in near real-time.

The DNSP or DSO use the ODNP to authorise data subscribers to relevant network operating data. Potential subscribers include the DER Controllers, the DNSP/DSO, and any other stakeholders approved by the DNSP. There is a range of commercially available communication protocols able to handle these requirements in a low-bandwidth, rural comms channel environment.

The ONDP also provides interfacing (via Application Programming Interfaces or APIs) where necessary between any DER installation recruited to the Scheme with any other actor or stakeholder carrying out DER Orchestration, DER Optimisation, or other task.

Other authorised data subscribers could include data users from the DNSP (e.g. network planners, PQ teams, network operators) and external actors or agencies, such as market operators, energy services aggregators, or regulators. Information exchanges could include, for example, the current DER output, current level of DER curtailment, current battery charge availability, and current position with respect to DER installation's operating envelope.

DDL CONTROL SCHEME MANAGEMENT

The second primary function of the ONDP platform is to provide a management portal for the DNSP of the entire system. The main task under this function is to administer the correct allocation or assignment of Dynamic Limits Profiles (and thus operating envelopes, see Section 7.3) to each DER controller and the network sensors to which they subscribe, and the relationship between these three aspects.

Through the ONDP, network planners will link all existing or potential DER network connection sites to the relevant network constraint location(s) to which they may contribute. These linkages are recorded in the ONDP and referred to in various audit and optimisation functions carried out at the ONDP level.

The network planner can also use the ONDP to set the shape of the Dynamic Limits Profile (DLP), which is used to determine the operating envelope for a given network state (see Section 7.3).

The use of unique DLP ID numbers allows every separate network constraint to have its own unique DLP operating curve. It is anticipated there will be a large number of groups that will have similar situations and will share similar DLP curves even though the Scheme will accommodate unique curves if needed.

The DDL Control Scheme also presents enhanced reporting and machine learning opportunities, not only at the DER Controller but also as added functionality in the ONDP. Examples of this include optimising issues such as curtailment fairness (equality or sharing of the available hosting headroom or export access available within the local supply group defined by shared network constraints), reporting overall renewable penetration, optimising hosting capacity, or compiling feedback reports that assist with optimising feeder tapping zones.

7.3 DYNAMIC LIMITS PROFILE

The third key component of the DDL Control Scheme is the use of a pre-assigned DLP. The DLP governs the response of the DER to a given network state, including the case when a network constraint is approached. The DLP curve represents the curtailment algorithm for the specified group of DERs and will cause appropriate curtailment behaviours to ensure acceptable network performance at the specified constraint location.

The DLP can be viewed as a predefined operating envelope for the DER installation across the full anticipated range of network states.

The DLP is set, reviewed, and approved by DNSP network planners with input from system control engineers as required. Modelling to date has created a number of templates for the DLP.

The shape of a DLP (or a group of DLPs) is assigned a unique ID number. The DDL Control Scheme then auto-generates a series of sibling profiles with unique IDs to enable the automated optimisation of issues such as curtailment fairness in any group on-the-fly. Machine learning can also be applied to improve the DLP, either autonomously or with prior review and approval by network planners and system control engineers, but is not necessary for base operation of the DDL Scheme.

The use of pre-assigned responses to actual network operating states at constraint locations, rather than the use of constraint engines or state estimation techniques to calculate estimates of the network constraint, is another key point of difference of the DDL Control Scheme.

7.4 DER CONTROLLER

The final key component of the DDL Control Scheme is the use of intelligent edge controllers operating in an IIoT framework, which serve as local DER Controllers. These local controllers store and implement the DLP and receive data from Network Sensors via the ONDP.

The DER Controller represents the intelligent end points envisioned in the IEEE Vision for 2030 and Beyond and the fast controllers at the grid edge described in the Newport Review.

A key requirement for the DER Controller is its ability to subscribe to Network Sensor data via the ONDP. This requires that it includes a software client that acts as an authorised data subscriber to the network sensor data relevant to the local network constraint(s) to which the particular DER site contributes.

The DER Controller uses the data from the Network Sensor and the DLP to establish the operating envelope — the ceiling of exports (and floor of allowable imports) given the current network state.

Intelligent DER controllers can also report data to, for example, improve visibility of DER behaviour or create forecasts of the net load over specific periods.

Manage Multiple Constraints

Each DER Controller can subscribe to and receive a DLP for multiple constraints and multiple profiles for a single constraint. Multiple profiles for a single constraint are arranged to become active given a specific network configuration, provided that the digital alerts of that changed network configuration can be provided to the DDL Control Scheme.

Manage Multiple Devices

The DER Controller at the site will then interact with the PV inverter (and, in the future, battery inverters, controllable loads, diesel generators, etc.) via any available comms channel (e.g. TCP/IP Modbus, RS485 Modbus, CAN bus, etc.). The DER Controller can then assert the relevant curtailment command (or none) as required to comply with the operating envelope established by the DLP and the near-real-time network data from the Network Sensor at the constraint location.

Future sophisticated DER installations involving multiple controllable aspects of load and generation may also require the DER Controller to implement supporting algorithms customised to the local DER installation. These would manage multiple components in a manner that achieves the DER customer energy choice priorities (e.g. maximising revenue from exports over any self-consumption at specific price thresholds) while also complying with the assigned DLPs.

Open Source Specification

Central to the DDL Control Scheme is that the DER Controller is based on clear requirements but delivered via third parties using a mix of Open Source (base scheme functionality) and third-party proprietary technologies (functionality extensions). None of the technologies used to achieve the required base scheme functionality will be proprietary to any one vendor to ensure competition among potential suppliers and choice for consumers.

The use of Open Source for the base scheme functionality of the DER Controller increases transparency, builds confidence in the Scheme's security, and fosters market innovation and competition.

This is achieved by making the base functionality software for the DER controller open source (for a list of approved, compatible hardware platforms) and developing open source functional specifications for integration into other hardware platforms. Novel and proprietary functionality extensions could be added to the base functional layers, to improve customer choice and facilitate competition among aggregators.

Although DER controllers are not commonplace currently, as consumers opt into DER Orchestration schemes such controllers will increasingly be required to extend the functionality inbuilt in inverters and to achieve backwards compatibility with older inverters.

The DER Controller as foreseen in the DDL Control Scheme is thus an attempt to advocate for the extension of the capability of the controllers that will likely be installed anyway, rather than an attempt to prescribe proprietary hardware either for networks, end users, or aggregators. The use of Open Source functionality is an attempt to achieve this.

The DDL Control Scheme is distinguished by the use of Open Source, intelligent DER Controllers based on an IIoT platform which are able to ensure adherence to the operating envelope relevant to any network constraint.

7.5 OVERVIEW

This section gives an overview of how the DDL Control Scheme operates using the framework developed as part of the OpEN Initiative's EA Technology Report (outlined in Section 5.3.2).

Under the framework, there are three key tasks to be implemented: determining the network constraint, defining the operating envelope, and communicating the operating envelope, as shown in Figure 10.

This section explains how the DDL Control Scheme achieves or contributes to each task.

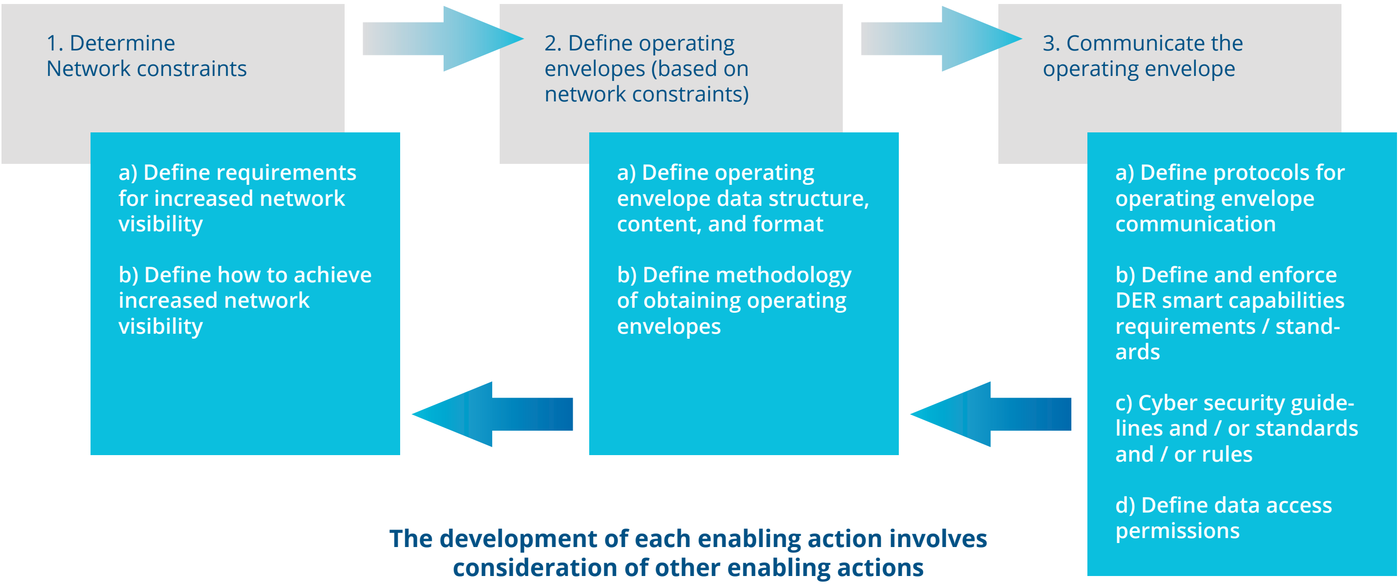


Figure 10 - EA Technology Framework for Implementing Dynamic DER Limits

DETERMINE NETWORK CONSTRAINTS

Under the EA Technology Framework, determining network constraints is enabled by two subtasks — defining the requirements for increased network visibility and defining how this can be achieved.

To achieve this the DDL Control Scheme relies on experienced DNSP network planners identifying each separate instance of local network constraints on their simple, rural networks in advance. Supply groups sharing a common network constraint will also share a common DLP. Appropriate network sensors are then specified for those local network constraint locations, assigned unique identifiers as network data publishers, and linked uniquely and securely to the ONDP data broker mechanism. By measuring the network operating states at these pre-determined network constraint locations using these network sensors, any subscribing DER Controller can be provided with direct visibility of the primary constraint(s) to which their installation contributes. This may include thermal constraints (current) on up-stream network assets, or voltage constraints either upstream or end of line, or a combination of all three. The network sensor publishes data on the near-real-time network operating state to relevant data subscribers, including DER Controllers that contribute to the network constraint.

Thus, the DDL Control Scheme defines the network visibility requirement as measuring each point of constraint, and this is achieved via direct measurement with a network sensor.

Having network planners review potential constraint locations and determine where the network sensors should be installed is usually a simple task for radial rural networks. In more urban, dense areas with integrated switching, this is a more complicated task, requiring network models and state estimation techniques. However, for regional networks and experienced network planners familiar with their network, the identification of local constraint types and locations and installing network sensors at those locations is likely to be a less resource-intensive task than ensuring that network models are up to date and conducting the necessary modelling to continuously re-verify the constraint types and locations, for all constraint locations everywhere, in real-time.

Thus, for regional and remote networks, measuring the network constraint directly is likely to be the simplest way to achieve the necessary network visibility.

DEFINE OPERATING ENVELOPES

Under the EA Technology Framework, the task of defining operating envelopes is enabled by two subtasks — defining the operating envelope data structure, content, and format, and defining the methodology for obtaining this.
The DDL Control Scheme defines the operating envelope through the use of the DLP. The DLP defines the operating envelope across the full range of potential network states at the constraint location(s), specifically addressing the allowable export or import capacity limits as the local network constraints are approached or reached.

The DDL Control Scheme has template profiles available that can be improved through the application of machine learning techniques. The DNSP's network planners and system engineers may also contribute to the development of the DLPs over time.

Thus, the DDL Control Scheme defines the operating envelope as the DLP, which is established by network planners and engineers across a range of network states and can be improved over time through the application of machine learning techniques and other initiatives.

COMMUNICATE THE OPERATING ENVELOPE

The final step under the EA Technology Framework is to communicate the operating envelope.

The DDL Control Scheme achieves this by communicating the DLP as an array data set to each assigned (or linked) DER Controller relating to that profile. The profile is then stored on the DER Controller. The DER Controller then receives network operating state data updates from the Network Sensor via the ONDP and uses the DLP to determine the current operating envelope.

A key point of difference for the DDL Control Scheme is that the network state is sent to the DER Controller, which then refers to the pre-assigned, pre-loaded DLP to determine the allowable DER capacity limit associated with the current network operating state at the local network constraint location(s).

This is in contrast to other approaches that assume that the operating envelope is continuously recalculated on-the-fly and then communicated to all relevant DER controllers.

Under the EA Technology framework, there are several enabling tasks that contribute to achieving the communication of the operating envelope. These include defining communication protocols, defining and enforcing the smart capabilities, implementing cyber security guidelines, and defining data access permissions, each of which will be discussed in turn.

The DDL Control Scheme has defined the appropriate communication protocol as a point-to-multipoint protocol implemented via a data broker. The use of a protocol in this manner avoids Latency Cascading issues and other challenges identified and outlined in Section 5.2.1. The flexibility and capability provided via the presence of a local DER Controller means that the communication interface with the local DER installation inverter(s) is most easily implemented.

The cyber security is an emerging field for smart grids. IIoT platforms are able to manage most cybersecurity requirements, although it is likely in the coming years that new standards and approaches will emerge to deal with this issue and the Control Scheme as a whole will need to be able to accommodate this.

The DDL Control Scheme manages access and authorisation through the ONDP, which is controlled by the DNSP. The DER Controller implements and reports on the compliance of the DDL Control Scheme. Software Version control for both the intelligent end point Network Sensors and intelligent end point DER Controllers is facilitated using administration tools provided in the IIoT Platform selected to host the DDL Control Scheme.

08
KEY BENEFITS AND DIFFERENCES OF THE DDL CONTROL SCHEME

The previous section outlined the Control Scheme components and how they work together to ensure that operating envelopes can be effectively developed and enforced. In addition to ensuring that local network constraints are managed, the DDL Control Scheme also offers a number of other benefits which are outlined in this section.

8.1 OVERCOMING THE NEWPORT CHALLENGES

The Newport Review highlighted several challenges that the dynamic management of DER may encounter: Hidden Coupling, Tier Bypassing, and Latency Cascading. This section explains how the Scheme's application of the principle of Subsidiarity, the use of Layered Decomposition, and the Scheme's operation at the lowest possible level in the control hierarchy can overcome these challenges.

One to-Many Communication Latency Cascading and Tier Bypassing

The DDL Control Scheme's implementation includes the use of one-to-many communication via a data broker. The ONDP allows DNSPs to manage and authorise subscribers and the data they receive. In this way, the ONDP communicates information on the current state of the network to all relevant stakeholders at the same time (i.e. in parallel).
Tier Bypassing is addressed as all stakeholders will have access to all relevant information on the grid state. Latency Cascading is addressed as information on the grid state is communicated directly to all stakeholders in parallel, and not routed through a series of organisations, each further contributing to communications latency. The use of the ONDP data platform thus directly addresses the challenges of Tier Bypassing and Latency Cascading.

Position in Control Hierarchy and Hidden Coupling

The DDL Control Scheme also implements DER Control for Local Network Constraint Management at the lowest possible level in the control hierarchy because the DER Controller is located at the network interface for each participating DER site.

This ensures three things. First, the communication loops for managing the time network state are as short as possible. Second, the DER Controller can ensure that network constraints are managed at all times. Finally, the fast control loop can respond to real-time network constraints (such as voltage fluctuations) and real-time market needs (such as frequency droops triggering a necessary DER response) while communicating with higher level control schemes seeking to implement DER Orchestration agendas, that are able to operate with a slower control loop (See Section 6.4 for more information).

Implementing DER Control for Local Network Constraint Management Control at the lowest level of the control hierarchy in this manner also solves issues of Hidden Coupling.

By providing information on the grid state to all (authorised) stakeholders in parallel, the Scheme ensures that DER Orchestration events that are approved through a DER Optimisation process will proceed within the technical limits of the network.

Any other dispatch command or event (such as a sudden increase in solar irradiance during a DER Orchestration event that is already exporting power) will be managed by the DDL Control Scheme to ensure that the network limits continue to be enforced.

If there are DER Orchestration agendas that would conflict with and threaten the management of network constraints, the DER Controller will prevent these from being implemented.

This prevents situations such as Hidden Coupling events — where DER Orchestration and DER Management tasks conflict, such as the one outlined in Section 5.2.1 — from arising.

Under the DDL Control Scheme, it is also no longer possible for DER Orchestration to create network problems that DNSPs would then need to procure DER Orchestration Services to solve. The technical limits of the network will simply be respected by any DER Orchestration agenda, including any combination of coincident agendas or resultant bid stacks. This is because the DER Controller enforcing the DLP will not permit the implementation of any combined bid stack that would exceed local network constraints. Once it becomes clear that the network's hosting capacity is placing excessive restrictions on DER, then the DNSP can look at options to upgrade the network once it is economic to do so.

The parallel communication of information in near real-time to all stakeholders via the ONDP gives all participants transparency over why network constraints may lead to DER Orchestration tasks not being completed, thus solving the challenge of Hidden Coupling.

Through the application of the principle of Subsidiarity and Layered Decomposition and the use of decentralised control to implement the Scheme at the lowest level (i.e. grid interface) of the control hierarchy, the challenges outlined in the Newport Review are all adequately addressed.

8.2 NETWORK VISIBILITY AVOIDS NETWORK MODELS

The DDL Control Scheme uses network sensors at the point of constraint to measure and report the current operating state of the network at those critical locations, rather than applying network models and constraint engines to estimate the operating state.

Essential Energy, for example, currently has hundreds of sub-transmission feeders and more than 1,500 Medium Voltage (MV) distribution feeders, each of which would require an up-to-date network model. In addition to these, if a DER control platform is adopted that relies on remote estimation of the network operating state using a constraint engine, then all of the LV networks supplied from the approximately 140,000 distribution substations would also need a model to describe them (and these are not currently available). This is because the majority of DER is connected at low voltage and the majority of constraints initially occur in local, low voltage networks. Given the lower average annual revenue per km of line characterised by rural and remote networks (See Section 6.5) this presents a major hurdle to participation in these schemes.

The DDL Control Scheme does require that network planners are able to identify the network constraints. The networks managed by DNSPs in rural and remote areas are characterised by their simple, mostly radial structure. As a result, constraints are usually obvious to experienced DNSP network planners and rarely change nature or location quickly.

The DDL Control Scheme is less well suited to complex or dense metropolitan networks with automated switching, multiple network layout scenarios, and constraint locations that can move. However, these dense networks often have a high revenue base that can justify the costs to establish (and maintain as accurate) the relevant network models, alongside the physical sensors and telemetry needed to report the current network configuration.

For rural, regional, and remote networks, the ability of the DDL Control Scheme to operate effectively without the need for network models is a major advantage.

8.3 STEPWISE IMPLEMENTATION AND RESOURCING REQUIREMENTS

A further major benefit of the DDL Control Scheme approach is that fewer resources are needed prior to launching initial capabilities and a roll-out can occur in an organic and step-wise manner.

DDL Network Sensors, DER Controllers, and related Dynamic Limits Profile assignments can simply follow recruitment interest in the Scheme, with roll-out priority given to network areas experiencing existing DER saturation and constraints.

This is a major advantage for the DDL Scheme. The Position Paper on the OpEN project released on 13 May 2020 notes (on Page 42, “No rush on distribution markets”) that all four of the OpEN framework models have less benefits than costs until very high DER uptake scenarios are reached.

However, DER uptake will not occur uniformly across the network. Thus it is critical that any platform enabling the control of DER for local network constraint management not require a large up-front investment in functionality applicable across the entire network in scheme development up front, prior to the platform functionality being available anywhere.

For the DDL Control Scheme, this is easily achieved. The major costs of the DDL Scheme relate to the provision of network sensors, the execution, administration, and management of the DLP assignments, and the upscaling of the ONDP as recruitment to the scheme increases. However, all of these costs can be focussed only on those network areas which already have (or are about to have) very high DER uptake and will otherwise require network augmentation capex to relieve local constraints. The roll-out of the DDL Scheme can occur in a fashion guided by and limited to only those network areas where network augmentation capex will be avoided by implementing the scheme.

The use of network sensors located at network constraint locations (together with relevant DLPs) effectively side-steps the requirement of developing and maintaining network models prior to the scheme's implementation for simple, radial networks (as discussed previously). Further, the network sensors are actively contributing to increasing the visibility of electricity networks. This improves what the Newport Review defines as Observability and what the OpEN Initiative's outlines as a “least regret” capability.

The combination of these factors means that implementation of the DDL Control Scheme can occur in a stepwise fashion — delivering benefits immediately where ever it is implemented without requiring a large upfront investment — while also contributing towards improving network visibility (or Observability), which is a “least regret” capability outlined by the OpEN Initiative.

8.4 IMPROVED VISIBILITY OF DER BEHAVIOUR

The visibility of DER behaviour is another challenge that this scheme can address. Consultation with stakeholders revealed that DNSPs do not currently have visibility over the compliance of DER within the current installations guidelines (such as compliance with AS4777's over voltage protections).

This problem is compounded by differences between manufacturer settings that may lead to unpredictable DER behaviour during disruptions. One example of this is the use of zero-point crossing methods for calculating voltage and frequency which can lead to unpredictable responses during disturbances. AEMO outline this challenge in their report on the Technical Integration of DER[12]:

> “Due to the absence of monitoring, the multitude of installed systems and variety in installed devices, it is difficult to collect information on DER and load behaviour during disturbances. This makes it challenging to develop suitable dynamic models that accurately represent DER behaviour, limiting AEMO's ability to diagnose challenges and likely necessitating future conservatism in the implementation of operational constraints. Improved monitoring systems, automated collection and warehousing of device settings, and ongoing processes for updating and adapting models need to be implemented.”

[12] Page 5. The full report is available here: https://bit.ly/2SFyUAq

The DDL Control Scheme's use of an intelligent DER Controller at each installation site creates the ability to compile intelligent, bandwidth-efficient, summary reports (and forecasts) of DER operating states (both current and historic). The reports could include key settings, responses during previous disturbances, or forecasts of DER capabilities over the next minutes, hours, or days.

The ONDP would then be able to share this data (subject to DER owner data privacy consents) to authorised data subscribers (including DNSPs, DSOs, aggregators, other energy services providers, and AEMO).

The use of the intelligent DER Controller in this manner is able to contribute to addressing the challenges of DER Visibility for both DNSPs and other stakeholders.

8.5 TRANSPARENCY AND VERIFIABILITY

The use of network sensors broadcasting data on actual constraints gives the DNSP control of the information flow about their network in a verifiable way.

This is in contrast to techniques employing state estimation or constraint engines to determine the location, nature, and threshold levels of each network constraint. Relying on constraint engines or state estimation techniques to determine where network constraints are located has two issues for regional and remote networks.

First, these techniques require up-to-date network models, which are not economical for rural and remote networks (as outlined in Section 8.2). The extent of the model required is also significant. For example, it is not sufficient to just know the equipment and conductor properties, locations, and route lengths. Operating regimes for all On Load Tap Changes, line Voltage Regulators, switched reactors, and fixed capacitors, plus tap settings on all distribution transformers and all nominal ratios and winding tap points for every transformer must also be known. For any DNSP managing a large rural network, these are extensive data sets to acquire and then keep up-to-date. However, without all of this data, the network model cannot confidently estimate the voltage levels that will be experienced at any given location on the low voltage network. As outlined previously, the DDL Control Scheme does not require network models.

Second, state estimation techniques and constraint engines are not transparent. The use of such techniques creates a reliance on the vendor because the only person who understands how the estimation technique functions is that vendor. The vendor not only controls information flows but also, essentially, creates them. In contrast to this, the DDL Control Scheme can create transparent information flows (through accurate measurement) that the DNSP controls (by authorising recipients via the ONDP).

Further, the estimation techniques relying on models cannot be verified as accurate without measurement. The only way to ensure that the technique is operating effectively is to measure the constraint location and verify the estimation technique against this. Otherwise, the only verification that a simulation is correct is further simulation. In contrast, the DDL Control Scheme will be as accurate as long as the network sensors are suitably calibrated and maintained.

There are no doubt applications where the use of these techniques is warranted. However, for regional and remote networks, the DDL Control Scheme provides greater transparency and verification while also being simpler to implement.

8.6 FAILURE MODES

A further major benefit unique to the DDL Control Scheme is that a wide range of failure modes are accommodated. The scheme can manage the failure of any of the Scheme's components — the DER Controller, the Network Sensor, or the ONDP.

UNKNOWN NETWORK STATE

The failure of a network sensor or a communication link informing DER controllers about the state of the network is managed by the Scheme in two ways.

Network Sensors Fail in Isolation

First, if a network sensor fails (or a DER is not able to respond to data about the network state), that failure is localised to that specific feeder or constraint. The data from the network sensor does not feed into interdependent calculations that other network segments rely on for an estimate of their state. Other network areas are able to continue under the DDL Control Scheme unaffected. Also, as described in Section 8.6.3, mechanisms exist within the DDL Control Scheme to ensure that failures of DDL Network Sensors do not go unnoticed.

Fingerprinting

The DDL Control Scheme includes an algorithm run continuously by the DER controller to build a fingerprint of operations during normal times when network operating state is available from the remote network sensor at the constraint location(s).

If a network sensor fails, or comms about the state of the network is lost, the intelligent DER Controller can provide a robust fail-back mechanism by referring back to the profile fingerprint in a structured manner defined by the algorithm.

Historic data is cross referenced and local voltages used to determine likely constraint conditions. For temporary comms losses, this fingerprint of historic performance can establish a likely operational envelope that is more conservative than the normal operating envelope but still applies DER limits in a dynamic fashion.

If comms isn't re-established sufficiently quickly, the controller can begin to revert back to a static limit. Without the local, autonomous DER Controller determining the operating envelope — and instead relying on centralised control platform to establish allowable actions of controlled devices — the possible Failure Mode Responses of those end points to a failure in the central control platform are inherently limited.

ONDP SINGLE POINT OF FAILURE IS A SIMPLE FUNCTION

The ONDP in the DDL Control Scheme does represent a single point of failure, in that the network operating data, DLP envelope assignments, DER operating data uploads, Data Historian, interfaces with aggregation/DER Orchestration platforms, etc., all rely on this platform.

However, the data broking function of the base ONDP functionality is a relatively simple function that can be most easily duplicated and mirrored. There are no complex or interdependent calculations occurring at this level.

How this is implemented would have to be considered in the detailed design of the architecture and operating modes of this platform to ensure all opportunities to enhance reliability and service availability are assessed and implemented where justified. This could include approaches such as service redundancy or mirroring/duplication acting in key elements of the platform. Data broking functions can be independent from one another, so that the collapse of one system does not affect the rest of the system, for example.

Through the application of distributed control principles, the DDL Control Scheme reduces single point of failure risks by ensuring that this point is also undertaking the simplest functions. This ensures that failure is less likely and that the impact on controlled devices is minimised.

DER CONTROLLER OR NETWORK SENSOR FAILURES

The DDL Control Scheme uses edge gateway devices (or intelligent end points) from an IIoT platform as the DER Controllers and Network Sensors. Whilst they perform very different functions, they share a common messaging protocol with stateful awareness that provides a built-in mechanism for the DDL Control Scheme to be able to tag any DER Controller or Network Sensor as being available, or not. This prevents failures from occurring but remaining unnoticed, enabling immediate corrective actions to be taken.

IIoT Platform Providing Common Failback Mechanisms

This stateful awareness architecture has the capability of issuing a Last Will and Testament. The Last Will and Testament is a simple mechanism which ensures that the "death" of a controller is followed by an orderly, pre-planned execution of previously outlined steps.

When a new DER Controller (or DDL Network Sensor) comes on line (or is repaired and put back into service), it first registers its state along with its Last Will and Testament. Receipt of this then triggers a birth certificate for the device, confirming it is on line and available.

If a DER Controller (or intelligent DDL Network Sensor) fails and falls off the network, then the messaging protocol server will publish a death certificate, carry out the Last Will and Testament action previously registered against this controller (or network sensor), and mark the device as being unable to publish data.

Last Will and Testament actions could also include sending alerts to any relevant party, including the DNSP and DSO. For a DER Controller failure this could include the DER customer, the system installer/integrator, or the relevant energy aggregator. For a Network Sensor failure this could include service technicians at the DNSP or any third-party agency providing the Network Sensor maintenance services.

These personalised alerts are possible because each DER Controller and Network Sensor under this IIoT framework is a dedicated device doing a specific task at a known location and the relevant service agency (and affected customer or customer group) will be linked to that through both the ONDP and the Last Will and Testament mechanism.

In combination, these processes ensure that no DER Controller (or DDL Network Sensor) will stay in a failed state without the customer, the DNSP/DSO, and other relevant parties being alerted.

DER Controller Failure

Monitoring and compliance functions are also carried out in the ONDP and act as a final check of normal operation of DER Controllers.

These functions use techniques to learn the normal behaviour of the connected DER and monitor and create alerts for changes. This functionality thus creates an additional check on DER Controller failure if the state awareness functionality of the messaging protocol fails for some reason.

Each DER Controller is local to a single installation and only controls that installation, so a failure of a DER controller only affects one site.

Network Sensor Failure

Network Sensors are generally relied upon by more than one DER customer and will often supply data to subscribers who are not DER customers at all. (For example, the Data Historian will be a subscriber for all data from all network sensors.)

Therefore, failure of a Network Sensor will usually affect more than one DER customer. However, in most situations, that Network Sensor failure will only affect one supply group (such as the low voltage supply from a single transformer).

In the case of long rural MV feeders where each DER Customer usually has their own dedicated transformer, the DNSP network planner will usually have nominated the primary remote constraint(s) as existing on the MV feeder. This means that all DER customers impacting that MV feeder constraint will be affected by a failure of that constraint. This is probably the worst-case scenario in terms of numbers of DER customers impacted by a single Network Sensor failure under the DDL Control Scheme. Even in this case, the failure is limited to this one group as all other groups refer to their different, unique local network constraints and related network sensors.

8.7 AUTOMATED REPORTING

The presence of an intelligent Network Sensor and DER Controller at each participating DER installation site means that intelligent reports can be compiled and sent to DNSPs, DSOs, Aggregators, and other relevant stakeholders.

The key advantage here is the flexibility and capability available to this reporting function due to the local intelligence. This means that valuable, customised reports can not only be configured for production on site and distribution via the data broker in a bandwidth efficient manner, but there is potential for customised reports to be developed specifically addressing any relevant issue (such as failure or safety).

For example, a Network Sensor at a distribution substation could also measure current levels in the earth return current to the transformer, to provide alerts to the DNSP about broken neutrals.

Network Sensors at distribution substations will also automate the return of Maximum Demand Indicator (MDI) data as a separate data stream unrelated to the DDL Control Scheme itself but made possible by it. This is a significant improvement on traditional MDI recorders at distribution substations requiring physical site visits to record the information and reset the drag-hand indicator devices.

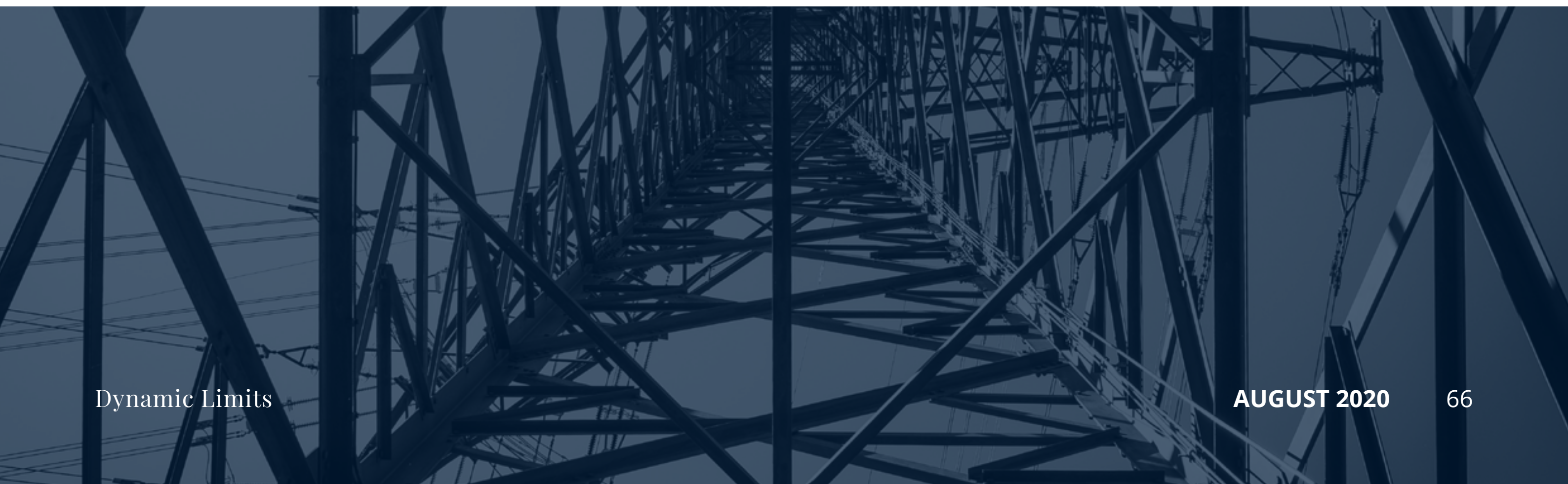
Network Sensors at three-phase distribution substations will also be capable of intelligently assessing abnormal voltages on the low voltage side, reaching conclusions about abnormal network conditions, and sending a customised alert to the DNSP Network Operator. The Network Sensors can do this for events such as one phase of the HV network being down, a low voltage fuse being blown, or a momentary outage of a predetermined duration occurring.

The same device will also compile routine reports about suggested tap changes to get average voltages for an LV supply group closer to the 230V nominal.

These intelligent sensors can also alert the DNSP for voltage supply conditions outside the normal operating range, for example, as might occur if a line voltage regulator failed.

Also, the compilation of intelligent reports via the ONDP can provide feedback to network planners if voltages measured at DER installation connection points indicate that a network voltage constraint location has moved, or the Dynamic Limits Profile assigned to a given network group of DER installations needs to be modified.

The DDL Control Scheme's use of intelligent network sensors that are capable of building custom data streams (such as alerts) to meet the needs of specific data subscribers (such as the DNSP system control) means that automated reporting possible within the DDL Control Scheme functionality can improve safety outcomes and reliability more generally in the network, beyond the issue of just providing dynamic limits management of DER capacities in a reliable manner.



8.8 COMPLIANCE

The intelligent DER Controller is also able to monitor and report on compliance with the Scheme by monitoring and comparing (and optimising for fairness) the curtailment levels of each DER Controller in any given supply group.

If any individual DER Controller starts exhibiting behaviours that are markedly different to its previous behaviour or that of other DER controllers in its supply group, then additional compliance audit responses or alerts will be triggered.

However, it is acknowledged that not all DER Controller curtailment behaviour changes necessarily imply non-compliance or DER Controller failure. For example, a customer with an oversize PV array may establish a certain history of curtailment of that large array but then may invest in a battery system that allows the customer to use the excess energy previously curtailed to now charge the battery. The compliance reporting function will need to be sophisticated enough not to trigger on false positives.

Legacy DER may be perceived as representing an obstacle for achieving universal recruitment and compliance. Many older sites will not have inverters that feature the external controller ports essential for participation in the DDL Control Scheme. They may also lack the communication capability to interact with any other external platform.

However, these older sites will typically be of smaller capacity (because of static limits historically imposed by DNSPs and the cost of DER systems being higher in the past) and will also reduce in proportion to compliant sites with aging and end-of-life replacement/upgrades. Any larger, older, non-compliant sites will require case-by-case assessment of the value of upgrading the site to comply with the DDL Control Scheme to qualify (or not) for increased capacity allowances.

In summary, the presence of local intelligent DER Controllers and ONDP functionality that enables comparisons between DER Controller behaviours in any group provides a strong framework for implementing any necessary compliance checking procedures needed.

8.9 CUSTOMER EQUITY

The use of Network Sensors and DER Controllers at each site enables the collection of data and the automated compilation of reports that can also contribute to addressing customer equity issues.

On-the-fly adjustments

For example, the DER Controller could keep track of curtailment levels and exports to the network. Moving averages or other forms of summary results could be uploaded to the ONDP for an assessment that compares these with other DER sites referencing the same DLP Family ID number.

This function would take into account relative DER base capacities at each site and adjust the assigned DLP sibling curve unique to each installation on-the-fly, to slightly increase or decrease the aggressiveness of the curtailment curve each site follows.

Whilst the primary storage place for all DLP curves and DER site assignments/links is within the ONDP, any changes made to these curves or their assigned sites is immediately pushed — in near real-time — to the affected DER Controllers. This means that a DER site being more aggressively curtailed than others in its group (on a percentage rather than kW basis) could be assigned a less aggressive DLP curve, on-the-fly and as required, to create the fairest sharing of network hosting capacity. This adjustment process would be continuous (in a slow fashion) to achieve a tight group of similar curtailment portions for all DER sites in any single group.

In this way, the ONDP can facilitate on the fly adjustments to the pro rata network exports and use of available DER hosting capacity headroom, ensuring that any required curtailment is fairly shared within any single supply group (sharing a common network constraint). Such an adjustment will improve equity and fairness.

Defining Customer Equity

It should be noted that customer equity could be defined in any number of ways. One approach to ensuring equity could include adopting a pro-rata curtailment relative to the installed DER capacities. This is likely to be the easiest approach to defend.

However, a pro rata approach to export fairness rather than curtailment fairness would account for the customer who does not curtail their large PV array as much as others because they have also invested in a battery to absorb excess energy.

Further work is recommended to explore customer attitudes towards any curtailment that may occur to determine what may be perceived as a fair approach while also ensuring that the system of curtailment does not create perverse incentives.

Comparisons Across Geographic Areas

A further example of the Scheme's ability to monitor and adjust for customer equity includes using the ONDP to compare curtailment across geographic areas to determine areas where changes are required.

For example, it can do this by comparing the rolling average energy exports between all DER groups and bringing focus to those DER supply groups that are, for example, in the lowest 10% of energy exported compared to all the other groups.

For these groups, the Scheme could combine data available from the Network Sensors assigned to that group, with reports coming back from the DER controllers, to identify which constraint is triggering the curtailment. For example, if an area is being excessively curtailed due to the voltage constraint threshold being reached too often, the data reported back to the ONDP can be used to confirm if the average Connection Point voltages at all the DER sites in the group are unnecessarily high. The Scheme could then issue an automated report to the DNSP network planner recommending lower tap changer settings for all distribution transformers supplying this group, and/or revised settings for any in-line voltage regulators or the 'On Load Tap Changer' programming back at the zone substation.

Overall, the use of Network Sensors and DER Controllers at each site enables the collection of data and the automated compilation of reports. These can be used to address customer equity issues among DER sites contributing to a single constraint and across geographic regions, and support DNSPs to make changes to their networks (such as transformer tap settings) to facilitate greater customer equity.

09
MAKING THE DDL CONTROL SCHEME OPERATIONAL

After establishing the benefits of the Scheme (Sections 4 and 8) and detailing how the Scheme could operate (Section 7), a round of discussions with a range of stakeholders was undertaken to identify issues that would need to be adequately addressed prior to implementation. These issues have been grouped into seven broad categories, outlined and discussed below.

9.1 THE CUSTOMER PERSPECTIVE

Several issues relating to the customer's involvement in the Scheme were raised across the various feedback sessions held. Concerns raised included equity among customers, privacy and confidentiality concerns, and the incentives required for customers to participate in the Scheme.

EQUITY

Discussions undertaken around the concept of equity examined concerns around how necessary curtailment as the result of a network constraint would not impact all customers to the same extent.

For example, some customers have a more immediate impact on a constraint than others by virtue of their location on the network. In these instances, how should the required curtailment among customers be managed?

For simple solar exports accessing a feed in tariff, there is an inherent tension that may arise between the dual goals of maximising the total renewable export into the network and providing equal DER export access to the network between all customers.

Any scheme implementing dynamic DER limits needs to be able to address and respond flexibly to these concerns.

Section 8.9 outlines how the DDL Control Scheme is able to address customer equity concerns and can be flexibly adapted to either achieve the most equitable outcomes or, alternatively, largest net export of energy from DER installations.

Further work is required, however, to determine the best and most acceptable way to understand the most acceptable ways to implement necessary curtailments in an equitable fashion.

PRIVACY AND CONFIDENTIALITY

A further issue raised during stakeholder consultations was the requirements of any scheme handling customer data to adequately satisfy the range of data privacy and confidentiality provisions, both existing in the current regulatory framework and developing (such as the Consumer Data Right and its application to Energy[13]).

The DDL Control Scheme must be able to satisfy all stakeholders that the measures taken to protect customer data and privacy adhere to all current and emerging legislations.

INCENTIVES FOR PARTICIPATION

A further issue raised was whether the incentive of allowing larger DER installation capacities would sufficiently incentivise recruitment of DER customers into the DDL Control Scheme. Similarly, commercial and industrial energy users' attitudes have also not been well discovered. Further research examining this area is recommended.

In rural areas with weaker networks, customers with either domestic or rural enterprise applications can often be prevented from connecting larger PV arrays or electrical loads that would create power quality or network capacity issues for other users on the shared network.

Considering the existing load and PV limitations imposed on customers in weak rural network areas, it seems likely they will embrace any new platform that permits some relaxation of these limits. The ultimate potential application for the DDL Control Scheme in this context is for significantly larger PV arrays, battery inverters, and site loads to be intelligently managed by the DER Controller. All of this would occur inside DLPs, for both import and export, to maximise benefits for the customer and the DNSP.

For example, in a voltage-constrained network area, the DDL Control Scheme would allow larger loads (or less export) at higher voltage times and lower loads (or larger exports) at lower voltage times.

This arrangement allows both larger capacities for loads and generation on site but also greater potential for customers to provide network support services in the future, which will be critical for DNSPs needing to minimise network augmentation capex. The management of import and export limits in this way enables the DDL Control Scheme to act as a platform facilitating the future development of large, rural, autonomous microgrids, loosely or lightly coupled to the broader supply network — but not completely dependent on it — and able to provide support services to it.

Further research is required into customer acceptance and needs for this type of future installation. Recommendations should be made around solution formats that would address some of the common needs that are being frustrated currently due to existing static network connection limitations on both import and export capacity.

[13] See, for example: ACCC, 2019, "Position Paper: Data access model for energy data" available here: shorturl.at/szQS7

9.2 SAFETY

A range of safety issues were also raised during discussions. None of these related to the DDL Scheme itself, but centred around existing network hazards that, under some circumstances, may be exacerbated through an increase of DER hosting capacity achieved through any implementation of dynamic controls for DER, including the DDL Control Scheme.

There are some common network safety issues that will have greater visibility and be easier to manage once the DDL Control Scheme is implemented. Some examples include the ability of a network sensor at a substation to alert remote System Controllers for local brown-out conditions, loss of a single HV phase, blown LV fuse, broken neutrals, overloaded substations, and momentary outage notifications.

Another example of existing hazards that DNSPs already encounter relates to the issue of “shocks and tingles” arising from broken or faulty neutral connections.

The DDL Control Scheme will be able to alert for these where a network sensor has been placed on a shared local substation because it is considered to be one of the local network constraints. That network sensor could directly measure normal “flow and return” currents in the active and neutral conductors and alert to any unbalance currents returning via the substation earth conductor.

However, in many rural situations with dedicated supply transformers, the DNSP Planner is not likely to nominate the transformer as a constraint (except for proposed DER capacities exceeding the transformer thermal limit) and this monitoring of the earth return current will not occur in these situations.

Another issue relates to voltage rise on neutral mains due to increased harmonics associated with the increased DER capacities allowable under any scheme increasing the hosting capacity of distribution networks. Third harmonics (and all Triplen Harmonics) arising from the use of DER inverters will increase if larger DER capacities are facilitated by dynamic control schemes. These Triplen Harmonics are additive in the neutral conductor and will drive higher neutral voltage rise issues associated with “shocks and tingles”.

The DDL Control Scheme does not currently include special provisions for detecting and alerting for increases in neutral rise voltages arising from increased DER capacities.

While these safety issues are the result of electrical infrastructure (either on the network or behind the meter) requiring additional maintenance or neutral impedance to be reduced by installing a larger capacity neutral conductor, the potential for DER Hosting Capacity to increase the impact of these safety hazards must nevertheless be recognised. Given that these issues will arise from any initiative that seeks to increase the hosting capacity of distribution networks, further work is recommended investigating this issue.

9.3 INTEGRATION WITH EXISTING SCADA AND DMS

Integration with existing Supervisory Control and Data Acquisition (SCADA) Systems and Distribution Management Systems (DMS) presents a key but manageable challenge before the Scheme can be implemented.

The existing sophistication reach and format of network SCADA and DMS systems varies considerably between DNSPs, but those managing vast rural and remote networks would generally have a greater amount of network that is either not visible or controllable remotely (or both).

Most key zone substation operating data is usually available, but the older and smaller sites can be lacking. Likewise, the currents and voltages at the head of most MV feeders is usually known but may not all be accessible remotely.

In the past 10 to 15 years, significant improvements have occurred in the number of installed modern reclosers on MV feeders, including those with remote control and status indicators. Some advances have also occurred in the sophistication and remote access to On Load Tap Changer and Line Regulator data.

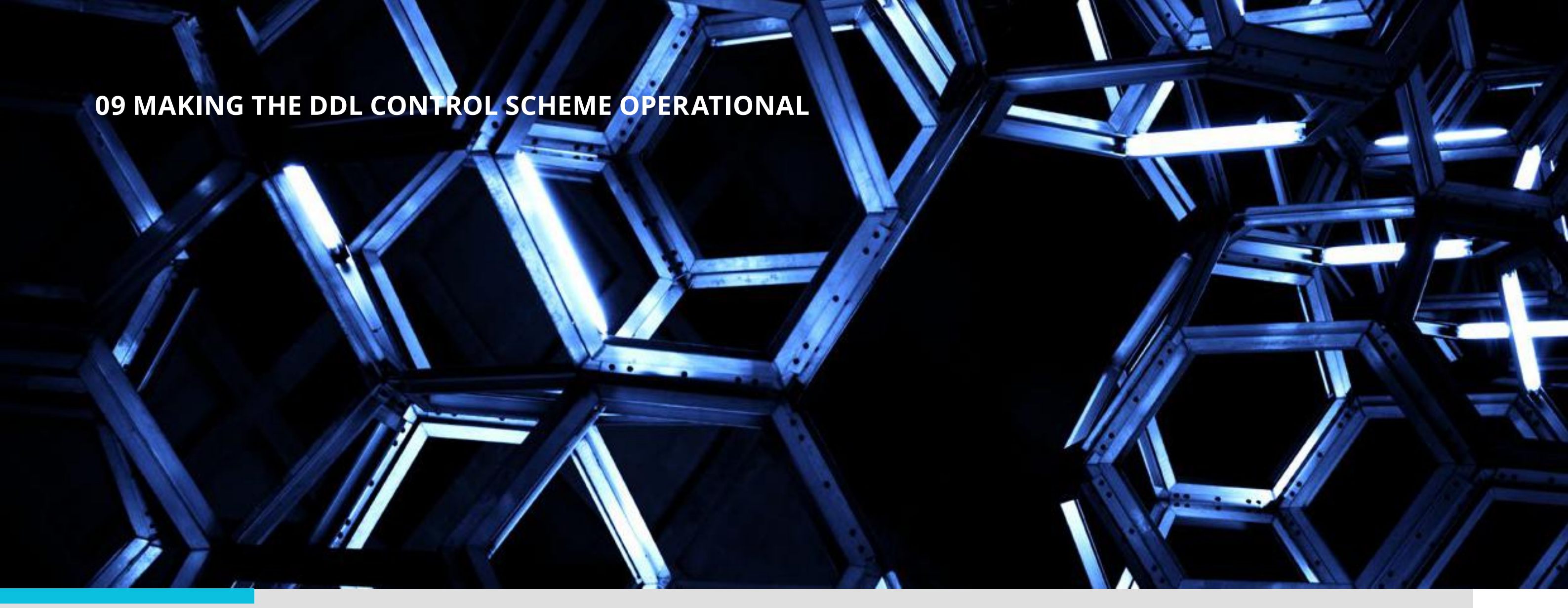
However, the visibility of low voltage networks remains a challenge. Rural DNSPs are trialling or beginning to install some limited facilities for remotely monitoring larger distribution substations in urban areas, but beyond that, the only knowledge of conditions at low voltage networks is from MDIs (usually only installed on substations greater than 100kVA and not visible remotely) or by manual site visits and temporary PQ logging audits by field technicians.

A subset of the total data available is usually stored in some form of Data Historian and the DMS (or similar) — in whatever shape that takes for each DNSP — usually only integrates with an even smaller data subset.

A broad and general challenge (and opportunity) facing all users of SCADA and DMS systems everywhere, is the emergence of IIoT architectures and related remote data and control solutions. It offers a completely alternative framework for the collection of field data and the remote operation of controllable field equipment. It also provides more convenient integration pathways between the field environment of Operational Technology (OT) and the corporate Information Technology (IT) platforms. IIoT architectures also facilitate administration mechanisms for the convenient remote update and management of software versions and functionality of remote sensors and actuators.

The DDL Control Scheme discussed in this report will utilise an IIoT framework, but regardless of what DER control platforms are implemented in the future, DNSPs will need to review IIoT opportunities anyway and decide to what extent they want to embrace IIoT approaches in their future SCADA (and DMS) capabilities.

Further study is required to determine data integration opportunities and pathways, and this would vary considerably between DNSPs. It would be significantly influenced by the long-term strategy each DNSP has with respect to embracing and integrating IIoT approaches (or not) in the future for their SCADA and DMS platforms.



9.4 CYBER SECURITY

Through the feedback and consultation process, a range of cybersecurity concerns were raised. These varied from the encryption and security measures used, to identifying and protecting from vulnerabilities (such as DDOS attacks, intercepting the over the air updates, or unauthorised access to data or to device controllers), how these can be both protected, and how the system as a whole can recover from any attack.

Implementing the DDL Control Scheme within a robust, industrial IoT platform will be critical to ensuring robust cyber security performance. Consumer grade IoT implementations have deservedly earned a poor reputation for cyber security due to cheap, unprotected sensors and actuators with direct connection to the public internet being subsequently infiltrated easily by hackers. This report does not identify a preferred IIoT platform, but multiple vendors have developed these and a critical assessment of the cyber security provisions would be required before any specific IIoT platform was chosen to carry the DDL Control Scheme.

Some work has already been undertaken generally in relation to cyber security in energy networks (such as the AEMO's Australian Energy Sector Cyber Security Framework[14]). However, further work in this area is recommended.

Prior implementation of the DDL Control Scheme a robust review is required to adequately address all issues raised by existing studies into energy network cyber security requirements.

9.5 DATA MANAGEMENT

In the stakeholder feedback sessions, three topics relating to Data Management were discussed at length. These include the use of third-party data sources, managing last mile communications, and ensuring data integrity and auditability.

[14] See here for more information: www.shorturl.at/bdrvO

THIRD PARTY DATA SOURCES

The possibility of adapting and integrating third-party data (such as smart meter data) was explored throughout this project. Although smart meters are a potential source of data, there are a number of issues that would need to be addressed to make this viable (excluding any confidentiality or privacy issues outlined in Section 9.1.2).

Issues identified include the limited view of shared network loads (because installation metering only considers loads in the specific installations), computation (often smart meters only take averages over specific time periods, which varies with configuration), alignment (smart meters are not necessarily all coordinated so that the sampling intervals equally align), and sampling frequency (meters only need to be read periodically, but the DDL Control Scheme requires near constant communication).

The implementation of the DDL Control Scheme will thus avoid using third-party data unless these issues can be satisfactorily resolved.

LAST MILE COMMUNICATIONS

The use of the DDL Control Scheme for rural and remote properties necessarily encounters a “last mile” problem — often the 3G/4G communication networks do not reach all customer sites.

This is a common problem for DNSPs managing rural and remote networks. The issue will usually have been the subject of separate studies by the DNSP assessing the extent of 3G/4G reach, any planned comms network upgrades, the number of electricity customers affected, and alternative schemes warranting further investigation or investment.

These considerations are always complicated by needing to understand any data integration and interfacing issues arising when combining a last mile comms solution over a broader 3G/4G internet access approach.

Commitment to any single last mile comms platform solution will first require a data integration and interfacing plan. The plan must confirm the compatibility and required functionality while also considering other possible future data sets and bandwidths required by the DNSP (and their customers, generally) in addition to the needs of the DDL Control Scheme itself.

There is a range of technology solutions able to address this, including LoRa (a low power, long range protocol). However, the particular solution chosen will need to not only serve the needs of the DDL control scheme but also other DNSP systems (and data sets) that require and benefit from this Last Mile communication network.

DATA INTEGRITY AND AUDITABILITY

Two separate but related issues were raised in relation to data integrity and auditability. First, from a cyber security perspective, data streams need to be monitorable and auditable to ensure compliance. This is also required to give various stakeholders confidence in the robustness and performance of the system.

The second issue relates to the communication protocols used and their ability to ensure that the data streams are relevant (i.e. the relationship between the sensor, DER controller, and profile are correctly established), timely (i.e. the DER controller is receiving recent data from the network sensor), accurate (i.e. is the network sensor operating correctly), and, where necessary, that a known degree of certainty is associated with the delivery of a given data set, among other things.

The scheme can address both of these issues through appropriate system design such as the use of appropriate communication, or hybrids of existing protocols if necessary, to achieve all requirements.

9.6 COMPLIANCE

Ensuring compliance with the DDL Control Scheme was a further issue raised during stakeholder consultations.

Currently, there are limited resources available for monitoring and inspecting physical solar installations for compliance with DNSP requirements. For this reason, the high number of smaller, common installations is usually undertaken as an audit across a smaller sample of all installations.

Further, access to passcodes, software interfaces, or hardware dongles for checking configuration settings in PV (and battery) inverters is not practical or efficient without the installing electrician in attendance. Specific issues such as compliance with PQ or Demand Response Modes add a further dimension to this.

The concern was raised that any scheme implementing the dynamic operating envelopes will add a further compliance burden to this already resource-constrained environment.

Any new DER control scheme that seeks to implement dynamic operating envelopes will need to have provisions for ensuring and enforcing compliance. It must not be possible for a DER installation owner or installing contractor to simply switch off the local site controller managing the DER limits. Any scheme seeking to implement dynamic DER limits will need to address these concerns regarding compliance.

The DDL Control Scheme is uniquely placed to ensure compliance, as outlined in Section 8.8. The compliance reporting requirements must address all DNSP concerns and be operational prior to the scheme's implementation.

9.7 INTEGRATION WITH OTHER EXISTING AND EMERGING ACTORS

A final issue raised during stakeholder consultation was the number of other actors (and their associated systems and technologies) that are pre-existing and emerging within the DNSP and more broadly across the energy eco-system. The DDL Control Scheme must be able to interface with the systems of these existing and emerging actors.

The advantage of the DDL Scheme is that the ONDP manages the interface with each energy services aggregation platform, eliminating the requirement for each aggregator to separately establish the interface with each DER installation directly.

INTEGRATION WITH EXISTING DNSP SYSTEMS

There is a wide range of existing DNSP systems (and databases). Some of these are very important in their own right and are potentially affected by the implementation of dynamic operating envelopes for DER. Any scheme implementing dynamic operating envelopes for DER will need to be able to interface and integrate these systems.

Existing systems include not just general frameworks such as GIS and related network asset databases, any ADMS and SCADA systems, Data Historian facilities, etc. but also specific existing (or planned) controls for larger significant DER sites (such as run back control and protection schemes or other control implementations).

One example of the integrations required is the link between the DDL Control Scheme and DNSP's existing GIS and network databases. The DDL Control Scheme operates by creating close, pre-identified links between the DER Connection Point and the related local network supply constraint locations performed as a one-off assessment by the network planners. This will benefit from a link between the DDL Control Scheme and the existing GIS and network asset databases.

A further example is linkages between existing monitoring systems available on MV distribution feeders and the DDL Control Scheme. Whilst the majority of new visibility of network constraints required by the Scheme will occur on low voltage networks, there will be some occasions where the Scheme could incorporate existing voltage or current data already available for the MV distribution feeders. In these cases, an interface would be needed between those existing data collection systems and the DDL Control Scheme.

Further study would be needed to identify the scope, issues, solutions, and benefits related to implementing these interfaces. A plan must be developed that can identify any complexity, vulnerability, and risk associated with integration. These must then be mitigated in a progressive, orderly manner. Creating such a data integration plan would be an important early step in implementing the DDL Control Scheme, not only to minimise disruption, duplication, or dysfunction with existing systems but also to produce the most benefit from new data becoming available as the DDL Control Scheme rolls out. This would have the added benefit of maximising the opportunity presented by the eventual adoption of IIoT approaches more generally across the DNSP operations and management layers (if that is a direction of strategic interest to the DNSP).

Integration with the DNSP's existing systems is a complex issue. However, it can happen in a step-wise manner, beginning with trial extensions with small scope, leading to broader application at scale once properly tested. But this does require a carefully planned approach.

OTHER INITIATIVES

In addition to the complex systems within DNSPs, there is also a range of other initiatives underway across the industry that any scheme implementing dynamic operating envelopes must also be capable of flexibly integrating with. These initiatives will use technologies and develop systems that the DDL Scheme will also need to be capable of integrating with.

This includes initiative that are creating new actors, such as Energy Networks Australia's efforts to define the role of the DSO[15], and new APIs and standards, such as for AEMO's Draft Guide to VPP Demonstrations API[16].

In addition to these, individual DNSPs (or sometimes groups of DNSPs) are also working on projects that are developing protocols and standards for information exchange.

To be successful, the implementation of the DDL control scheme will need to adopt, build on and/or be capable of integrating with these wherever possible.

15 See the Energy Networks Australia 'Open Energy Networks' page for more information here: https://bit.ly/2LNTElR
16 Available here: https://bit.ly/3cU8xib

10
SITE SPECIFIC FEASIBILITY ASSESSMENT

This report has already established the feasibility of implementing dynamic DER control schemes generally (Section 4), outlined the functionality of the DDL Control Scheme (Section 7), and benefits (Section 8) and challenges (Section 9) of implementation. Now, two real-life rural network models and a third hypothetical model are used in the following assessment to consider the impact of implementing the dynamic management of DER capacity on rural electricity networks.

10.1 THERMAL CONSTRAINT STUDY: SEMI-RURAL VILLAGE, FOUR HOUSES, SHARED TRANSFORMER

FEEDER DESCRIPTION

The KTE3B4 Kundle Kundle feeder from the Kanangra Drive zone substation in Taree is a short rural 11kV feeder supplying a mixture of agricultural lots, hobby farms, urban residential, and small rural lots. The feeder has 33.4km of high voltage network, 1.7km of which is underground. In 2018, there were 644 customers connected to the feeder, contributing to a maximum demand of 1.93MVA.

We modelled just one small, rural residential, low voltage group of four houses on this feeder, supplied by a small three-phase transformer. This group was known to be experiencing voltage constraints as the level of connected solar generation had increased.

The study models the extent to which the houses on this feeder could increase the installed solar sizes beyond the rural static limit of 3kw if dynamic DER controls were to be implemented.

Long term (two year) average hourly insolation levels for the year at this rural NSW general location were used to predict the likely hourly, daily, and total annual generation from the PV arrays.

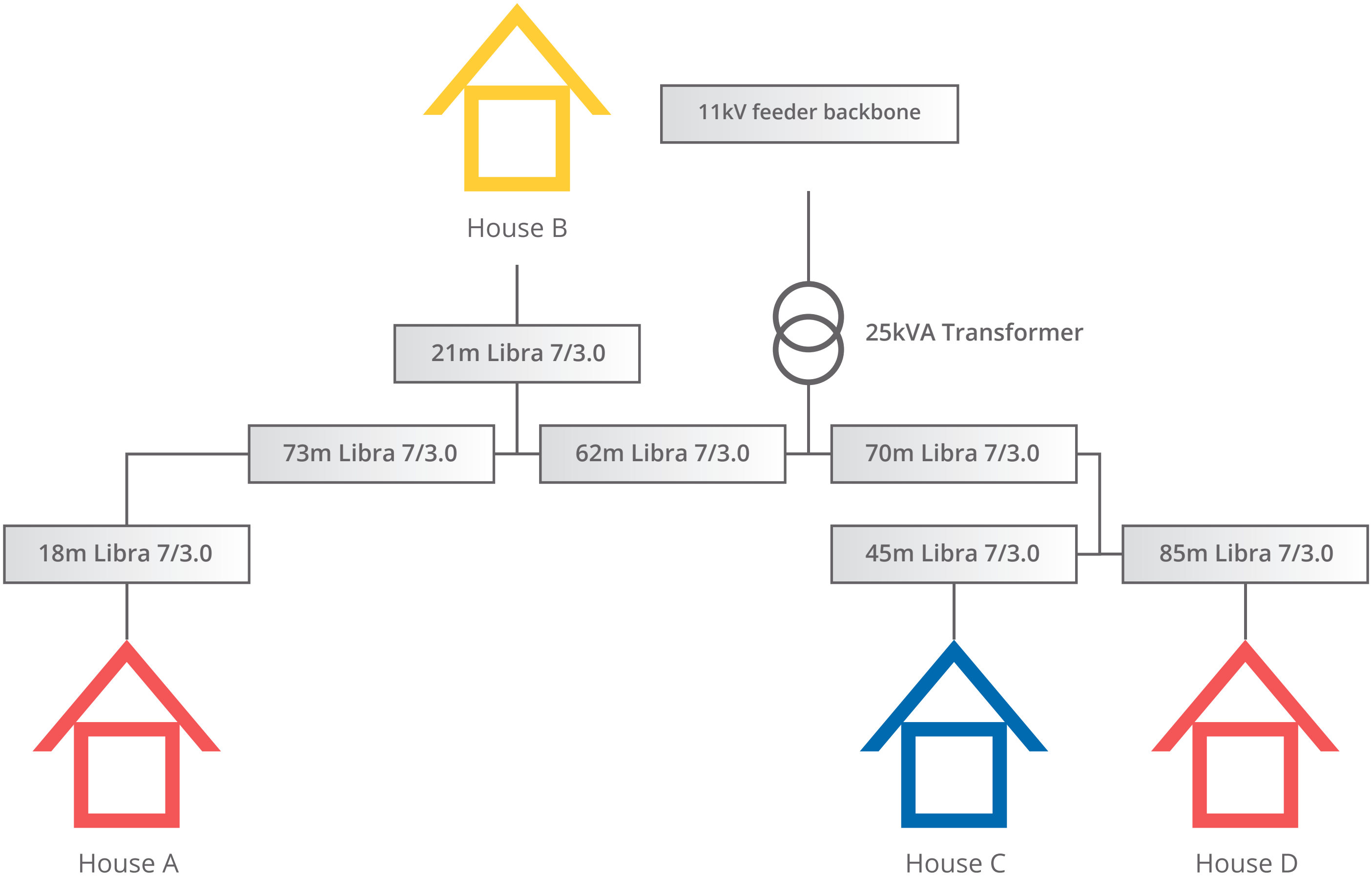


Figure 11 - Spatial Arrangement of the Brimbin Village on the Kundle Kundle Feeder

The model assumed all four houses started with a 5kW array each to set the base line local generation capacity and then considered what increases in PV capacity might be possible if dynamic limits were applied to these system capacities.

This provides a maximum total export capacity (during zero load times) of 20kW. Evaluating the worst-case scenario in the existing system in terms of the operational window, the red phase customers may both be exporting 5kW to the grid, a total of 10kW, which exceeds the nameplate thermal capacity limit (8.3kVA) per phase of the transformer.

THE FEEDER MODEL

A standard feeder model was supplied from the DNSP model library, to take upstream voltage supply and impedance into account for this study. Also, an additional Python modelling tool was used to examine the LV network just in the Brimbin locality of the four houses and single transformer. This tool was used to accurately represent the supply situation for these four houses unbalanced over three phases over all hourly periods in the applied annual load and generation profiles for the houses and arrays, including consideration of the local supply conductor types and lengths.

Another important issue for maximising DER hosting capacity relates to the upper voltage constraint. Networks commonly supply customers with average voltages that are on the high side of the nominal 230V standard. Correct implementation of line voltage regulation programs and tapping zone schemes for feeders is essential for creating the optimum voltage rise headroom for DER installations prior to consideration of introducing sophisticated dynamic curtailment platforms for DER.

A Python load flow program was used to calculate voltage levels for all net load combinations of import and export on each phase. An operational window, as shown in Figure 12, was defined to represent the allowable operating zone, with each house on the chart represented by their nominated phase connection colour (R/Y/B).

CONSTRAINT MODELLING

In the modelled example, the Blue house reaches a voltage constraint before reaching the thermal constraint and real-life conditions would be worse than this. The no load voltage model result of 244V is lower than would be expected in real life because the MV feeder input voltage to this supply group was taken at the maximum load scenario on the main feeder backbone when the voltage drop along that backbone is most significant. A true no-load scenario would likely generate a no-load voltage in the village that was higher than 244V.

If each house individually exports the maximum amount of (transformer winding limit) power with no standing load, the voltage will rise, and the full transformer thermal capacity will be utilised in the export direction. The voltages at each house under these conditions are shown in Table 5, which shows that the thermal constraint is reached first but coincides with a voltage constraint also for House C because it will exceed 253V if the no-load starting condition is as high as 244V. This voltage constraint could be relieved simply by lowering the tap setting on the transformer. A 2.5% reduction (6V) would give a no-load starting point of 238V and limit the rise for House C to 249V, which is under the 253V upper limit.

In Table 5, we note that House C on the Blue phase would be voltage constrained if we did not lower the no-load voltage by adjusting the transformer tap setting.

	NO EXPORT	MAXIMUM EXPORT (*) WITH NO LOAD			
	No load (V)	House A (V)	House B (V)	House C (V)	House D (V)
Red phase	244. 0	251. 1			252. 3
Yellow phase	244. 1		252		
Blue phase	244. 1			255. 0	

Table 5 - House Voltages under Maximum Export Conditions

(*) – Maximum export is referring to the 8.3kVA limit per winding, but Houses A and D share a winding so in normal circumstances would be limited to half this level of export each, with corresponding lower voltage rise results.

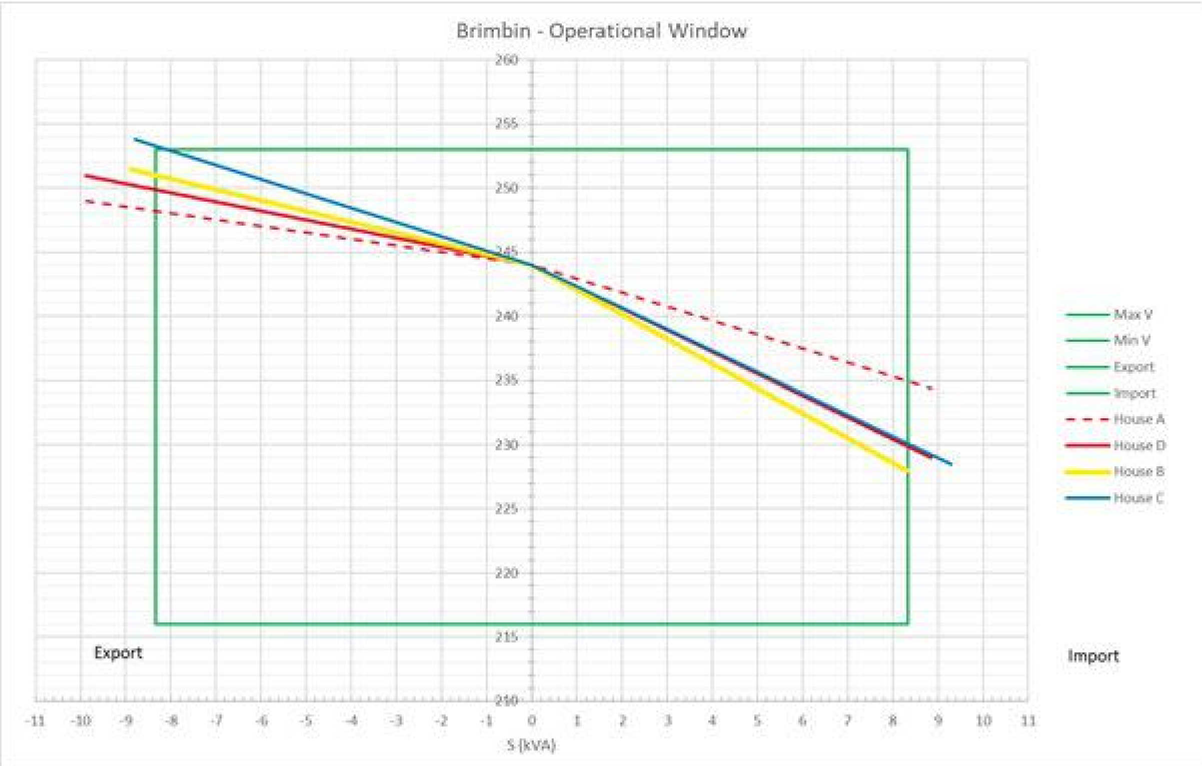


Figure 12 - Brimbin Village Operational Window

Figure 12 shows how the voltage drops for loads imported (RHS) at 0.85 lagging power factor and how the voltage rises for generation exported (LHS) at unity power factor.

Figure 13 adds two vertical thermal limit lines relating to the transformer windings. (The two customers who share a winding are limited to only half the current rating in export or import, compared to the customers who don't have to share a winding).

At any time, each customer may be at any point on this axis due to the nature of their load and generation capability. Restricting the amount of generation installed to an arbitrary (and static) value for all the customers in this village results in a restriction in the available export capacity from each house. With these restrictions in place, as shown in Figure 13, there is a clear loss of system capability because it prevents network operating states to the left of these limits.

If the present constraints of 3kW for rural are imposed, the maximum installed capacity this village can have is 12kW or just under half the available thermal capacity of the transformer, 38% of the winding capacity for the single customer windings, and 75% of the winding capacity for the two customer connections.

Alternatively, when we apply a dynamic management approach to limitations on DER capacities, the amount of power that is delivered to the network is dynamically allocated based on a thermal and/or voltage constraint. If the two vertical static limit lines are removed then the installed capacity could rise to the full thermal capacity of the transformer (and beyond, provided curtailment is correctly applied).

Increasing the installed generation capacity above the transformer capacity is an option because of the likelihood of some of the customers on the transformer also absorbing some power in the form of loads at their installation. If the urban (5kW) static limit constraint is applied to this rural village, the capacity available to be installed would be 20kW, closer to the total transformer capacity but exceeding the capacity in the case of the single winding supplying two customers. On a day with full sunshine but no load in either house, this single winding nameplate rating would be exceeded by 20%.

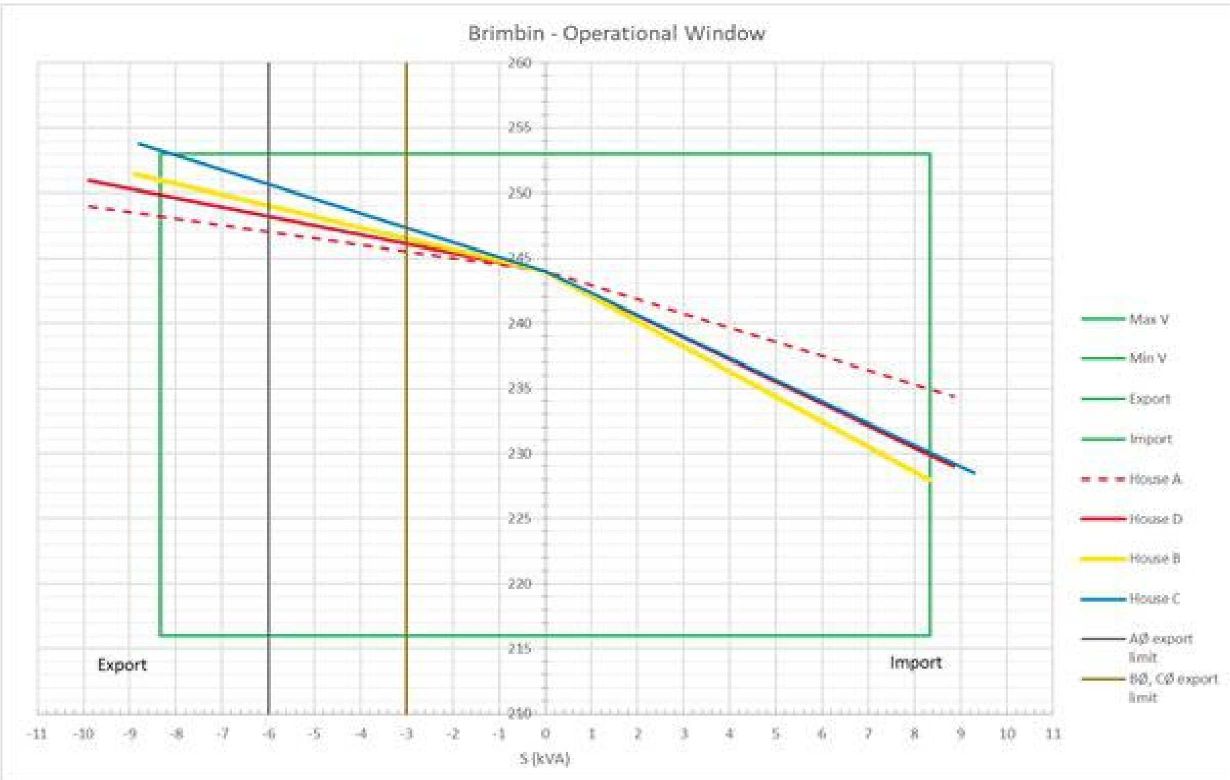


Figure 13 - Export Limits Imposed on Brimbin's Operational Window.

MODELLING CONCLUSIONS

The modelling concludes that the no-load average voltage level is too high and could be addressed by reducing the tap settings by a minimum of 2.5% (6V on 240V base) or 5% (12V) preferred, to provide a lower average supply voltage. The existing 3kW static limit applied to DER on rural houses could be increased to 8kW for two of the houses (an increase to 266% of the static limit) and 4kW for two that share a common transformer winding (an increase to 133% of the static limit), without any dynamic curtailment scheme being needed.

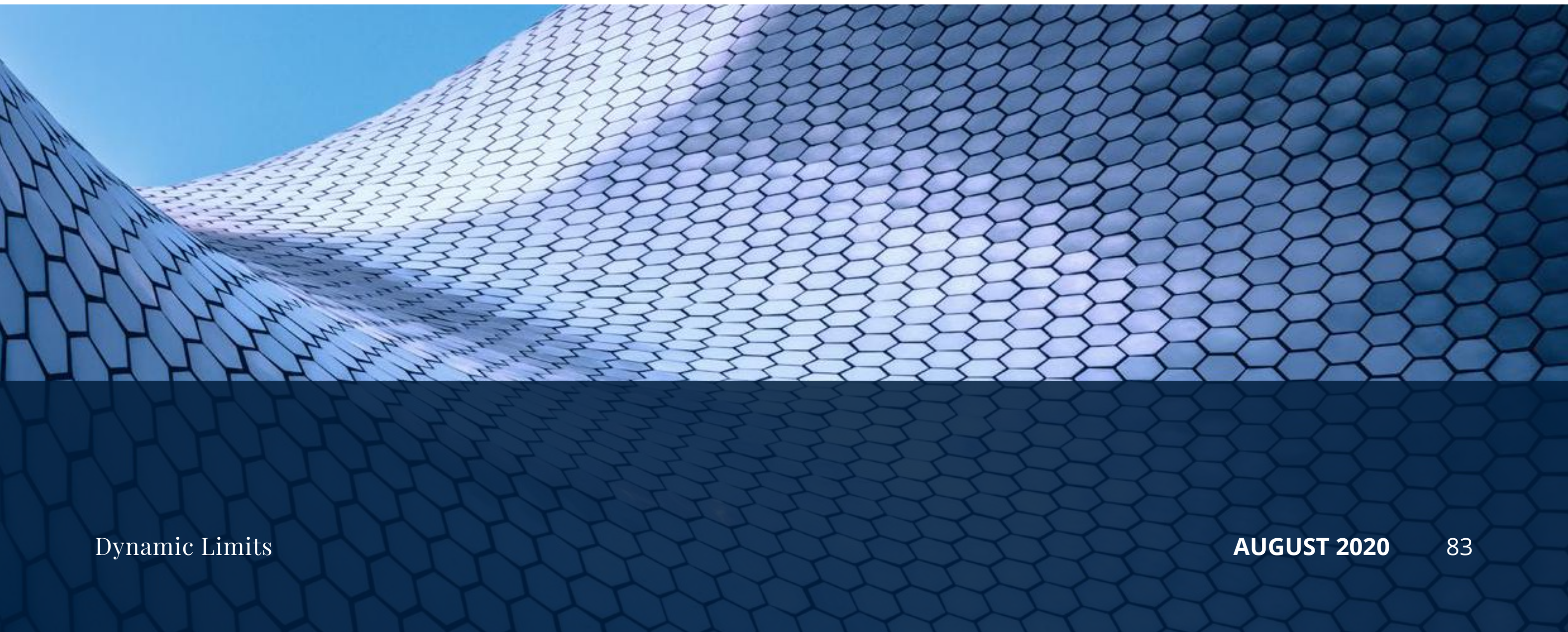
ADMDs are higher for small customer groups like this and the implications for exceeding transformer thermal constraints are made worse when small three-phase transformers are used to supply small numbers of single-phase customers. This is because the individual transformer windings are only rated at one third the capacity of an equivalent single-phase transformer where all connected load is supplied by a common winding.

If the transformer was changed to a single-phase 25kVA unit and dynamic curtailment of DER were applied, then modelling of loads and generation in hourly intervals for an entire year showed that zero curtailment would occur if each house had 10kW installed. Only 12% curtailment would occur if 15kW were installed per house (an increase of 500% compared to the static limit). This represents a five-fold increase in allowable DER capacity but does rely on a lower tap setting being applied at the transformer and the existing three-phase transformer being replaced with a single-phase device.

If the existing transformer remains, then curtailment increases because the load diversity (and winding capacity) per phase is less. Additionally, houses A and D sharing the single transformer winding would experience additional curtailment compared to the other two houses and their optimum maximum array size would be reduced to less than 10kW.

The Brimbin village demonstrates the ability of a small group of houses connected via a small distribution transformer to host a larger capacity embedded generation system than is currently accepted if the dynamic control over the generation output takes place to ensure that thermal and voltage constraints are not exceeded. (This is particularly so if the existing three-phase transformer is replaced with a single-phase device of the same rating).

The application of a dynamic control over generation effectively restores the capacity bandwidth in the network that is presently trapped by constraints well below the capability of the network to absorb power. In the case of this small network, a reduction in transformer secondary voltage would result in a broader utilisation of the operational window for the location.



10.2 VOLTAGE CONSTRAINT STUDY: LONG RURAL FEEDER, LARGE DER TRIGGERS 3% RULE

FEEDER DESCRIPTION – WALGETT WGT8B2 22KV

This is a long rural 22kV featuring a total route length of 282km. It supplies a mixture of three-phase and Single Wire Earth Return (SWER) distribution servicing customers on agricultural land and a small village. The 107 customers connected to the feeder contribute to a maximum annual demand of 450kVA.

The Mink conductor (6/1/0.144 ACSR/GZ) feeder backbone has a 4MVA thermal limit at 22kV and only carries 0.45MVA peak annual load, suggesting generous unused headroom for both more load and more generation. Also, the DNSP Planning Guidelines allow a voltage swing on rural feeders between 93% and 105%.

Side Constraint: 3% Voltage Change Limit Rule for DER Installations

In addition to the upper and lower thresholds of allowable voltage range at the point of supply for each customer, DNSPs may also apply a Voltage Change Limit rule for significant DER installations (and loads). The concern relates to the situation where the DER generation drops from 100% rated output to zero instantly, such as when a protection shut-off event occurs. In this situation, the DNSP may specify a maximum allowable voltage change that will be tolerated on the shared network as a result of this. The DNSP managing the Walgett Pilliga network area requires this limit to not exceed 3%.

In this study, at the chosen site, that upper capacity limit turned out to be 1.01MW. DER installations larger than this would not meet the criteria (unless limited dynamically to a flat ceiling of 1.01MW).

The study models the impact of a hypothetical DER site at the end of the three-phase feeder backbone, near the location where the feeder changes to a low capacity SWER line.

With dynamic curtailment implemented and without the 3% rule applying, DER sites of several MVA capacity could otherwise be easily accommodated at this site. Modelling at this site shows that there are no conditions throughout the year where dynamic curtailment would be needed if the DER capacity is limited to 1.01MW.

However, normal voltage regulation on the feeder varies over a range of approximately 1.7% and, if the 3% rule did not have to be accommodated, then the feeder could otherwise tolerate between 1.2MW and 2.25MW at this location (with this variation being driven by the voltage regulation changes). When the feeder is at the top of its voltage regulation range, it could only absorb an additional 1.2MW, but at the bottom of the range, it could accept 2.25MW. A dynamic curtailment scheme would only normally have to curtail between these two levels (for the current feeder situation) and the voltage constraint is dominant (thermal constraint not reached).

THE FEEDER MODEL FOR WGT8B2

A simplified diagram of the feeder is shown in Figure 14.

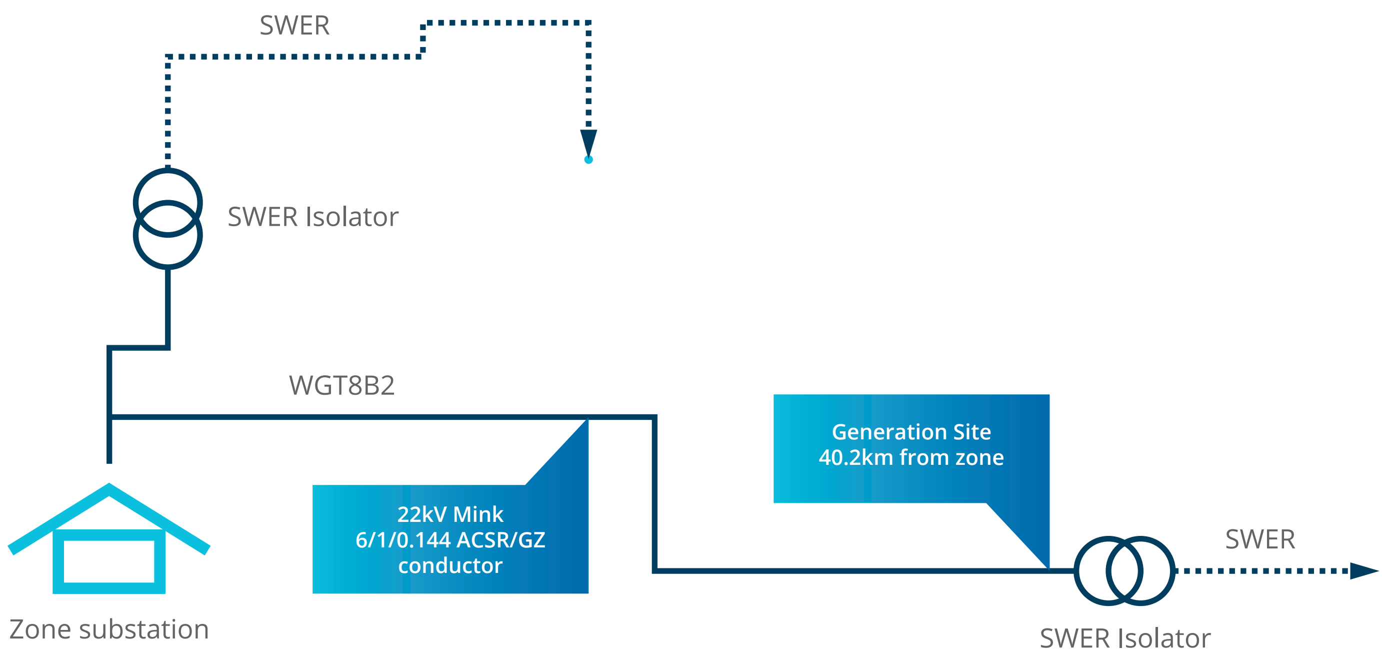


Figure 14 - Pilliga Feeder General Arrangement

The thermal limit of generation is set by the Mink conductor to 4MVA. If the proposed DER site were to incorporate storage or other potential load, the maximum load limit would be defined by both the Mink conductor and the peak demand on the feeder, giving a theoretical maximum load of 3.55MVA.

Assuming the DNSP has set the tapping zones correctly for all connected distribution transformers, the voltage limitations are defined by the allowable voltage range on the high voltage feeder.

OPERATIONAL WINDOW FOR THE PILLIGA FEEDER

The Operational Window, outlined in Figure 15, illustrates both the voltage and thermal constraints and their relationship at the chosen hypothetical DER location near the extreme end of the three-phase feeder backbone.

Figure 15 - Disruptive Site Operational Window

The allowable range for Network Planning purposes for rural MV feeders is typically 0.94pu to 1.05. However, at times, this is expanded at the top end for short term operational needs by System Control to 1.10pu, with alarms occurring at 1.07pu.

For the purposes of this study, the related maximum DER capacities are referenced to this more conservative 1.05pu limit, not the operational limit of 1.10pu.

Without the proposed DER generation, the feeder voltage is well regulated, changing by only 1.7% during a typical 24-hour day on average, as shown by the blue line in Figure 16. This range of voltage variability was then modelled, producing the chart in Figure 17. The impact of the upper voltage constraint can be seen in the upper left of Figure 17, effectively limiting the maximum output before the feeder thermal limit (yellow vertical line) comes into place.

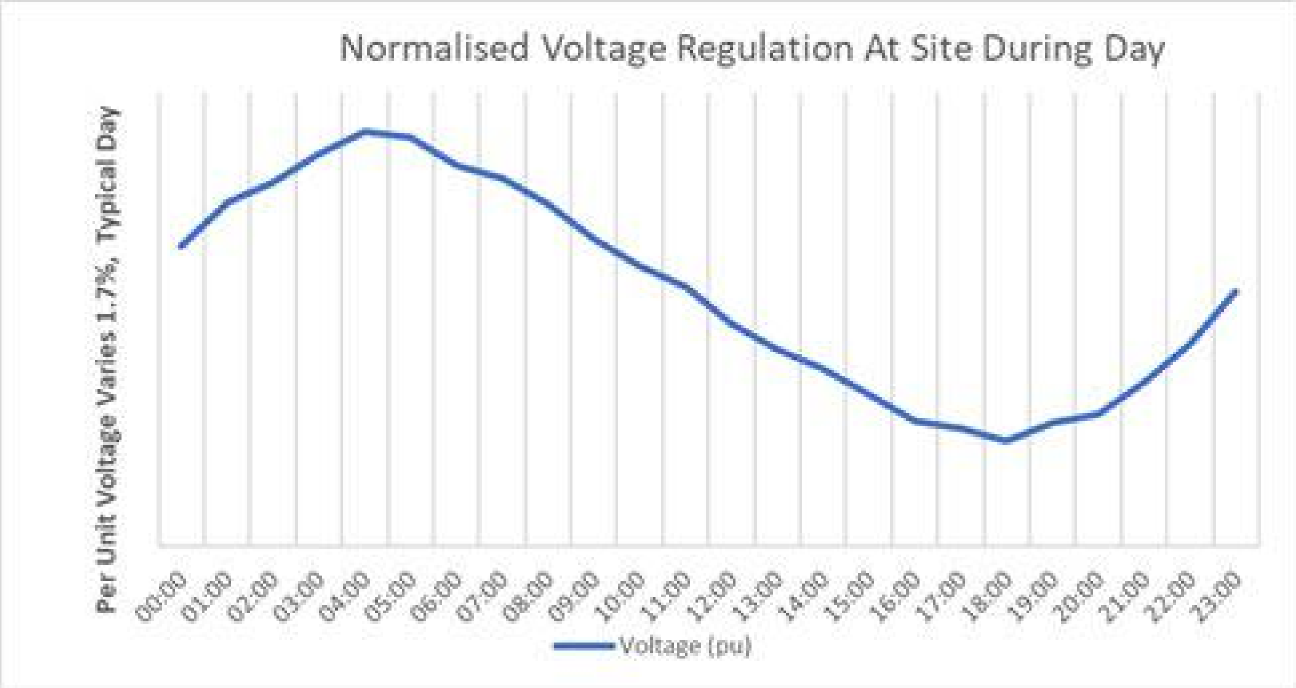


Figure 16 – Typical Daily Variation in Voltage Regulation

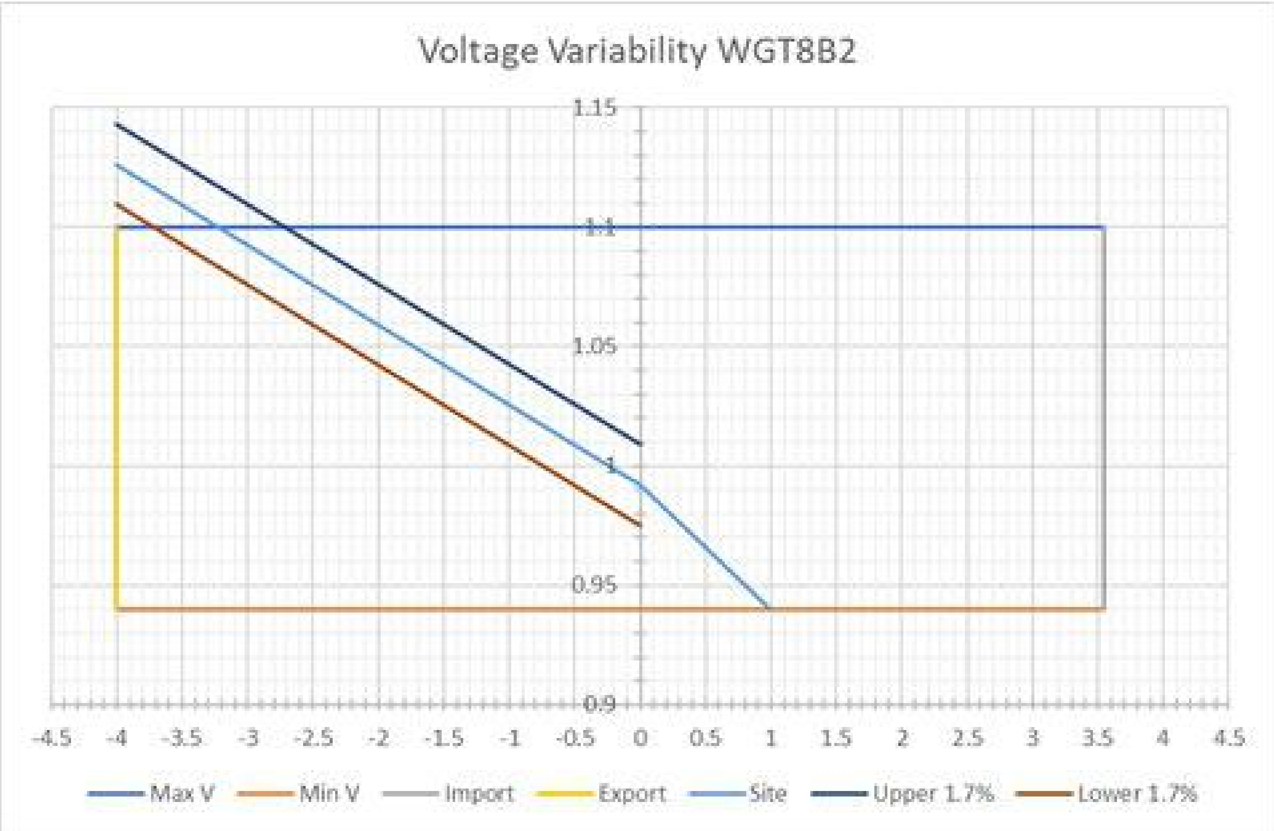


Figure 17 - Additional Export Range Based on Voltage Variation.

MODELLING CONCLUSION

The DDL Control Scheme for imposing dynamic limits would continuously accommodate this 1.7% voltage regulation variation by measuring the actual network state voltage at the constraint location in near-real-time, thereby allowing confident control of the DER generation. The DDL Control Scheme would recognise the upper voltage condition when it occurred and curtail down to this 1.20MW limit but be free to curtail less — up to a modelled maximum of 2.25MW export — at times when the lower voltage condition exists.

Given that the 3% Voltage Change Limit rule does apply, the option of installing a 2.25MW DER generator controlled by the DDL Control Scheme is not an option, so the annual energy output and curtailment level of this 2.25MW DER was not modelled and the estimates of annual energy amounts delivered and curtailed were not produced. However, the modelling does suggest that the DDL Control Scheme could satisfactorily control a 2.25MW DER site at this location without the voltage constraints of this feeder being exceeded. This is a 123% capacity increase over the 1.01MW limit arising from the existing 3% rule applied by the DNSP.

The DDL Control Scheme could also satisfactorily contain an oversized array (i.e. larger than 2.25MW) within the curtailment zone (1.2MW to 2.25MW) predicted by this modelling, if there was a motivation to chase higher energy yields by tolerating a flat-topped daily yield curve, constrained under the 1.2MW to 2.25MW limit (as the feeder voltage regulation varied through the typical day).

10.3 VOLTAGE CONSTRAINT STUDY: SINGLE RURAL HOUSE, LONG LV SUPPLY

SUPPLY DESCRIPTION AND VOLTAGE CONSTRAINT

After encountering the 3% voltage limit rule on the first voltage study, a further study was conducted to better explore the potential increases in supply available through the implementation of a dynamic DER limit on rural networks.

This study examines modelling of a single point rural customer load (house), which was small enough to not trigger the 3% Voltage Change Limit rule imposed on DER installations but was supplied through a reasonably long (100m), small conductor (Chlorine 7/2.50 AAAC), low voltage mains and then a maximum allowable length (50m) of modern (Aluminium XLPE 25mm2) service wire.

This supply arrangement is not voltage constrained for a rural DER installation complying with the static capacity limit of 3kW. It starts becoming constrained by the upper allowable voltage threshold (253V) at the customer's main switchboard once 15kW DER generation is installed.

This low voltage supply is supported by a 25kVA, 240V nominal single-phase transformer with tap position (and general MV feeder regulation) set to deliver the nominal target 230V average voltage at the customer's main switchboard.

Note that this model assumption about the 230V average supply voltage level does provide the maximum/optimum capacity of DER hosting headroom on the LV mains and service wire segments of the supply because the voltage must rise 23V in export before the upper allowable supply voltage threshold of 253V is breached. Hence, the maximum DER capacity identified in the following modelling as being possible without any dynamic limit curtailment being needed is the highest figure likely to be achieved in real life. Usually, average voltage levels at the customer's main switchboard are more often 240V or higher and these decrease the voltage rise possible under export before the upper allowable threshold level is breached.

MODELLING OUTCOMES

The modelling showed that the existing 3kW static limit could be increased to 5kW without any curtailment required and a 10kW array could be installed with only negligible levels of curtailment (<1%) required to stay under the upper voltage constraint.

However, once a 15kW array was installed, 8.1% of the total potential annual PV energy yield was lost to curtailment to remain under the 253V upper voltage constraint. The PV energy delivered still totalled 25,404kWh annually compared to the 5,526kWh annually that might be expected from the normal 3kW static PV capacity limit that would typically be applied to a rural house. This represents a 360% increase in the PV energy that could be utilised (either locally or into the network) compared with the output of the standard rural maximum 3kW static limit system DER capacity.

DER capacities higher than 15kW could be installed but curtailment portions increase quickly.

In the following graphs, the horizontal voltage axis is marked in per unit base. This means that the upper voltage limit of 253V is 13volts (or 5.4%) above the base of 240, so is shown as 1.054pu.

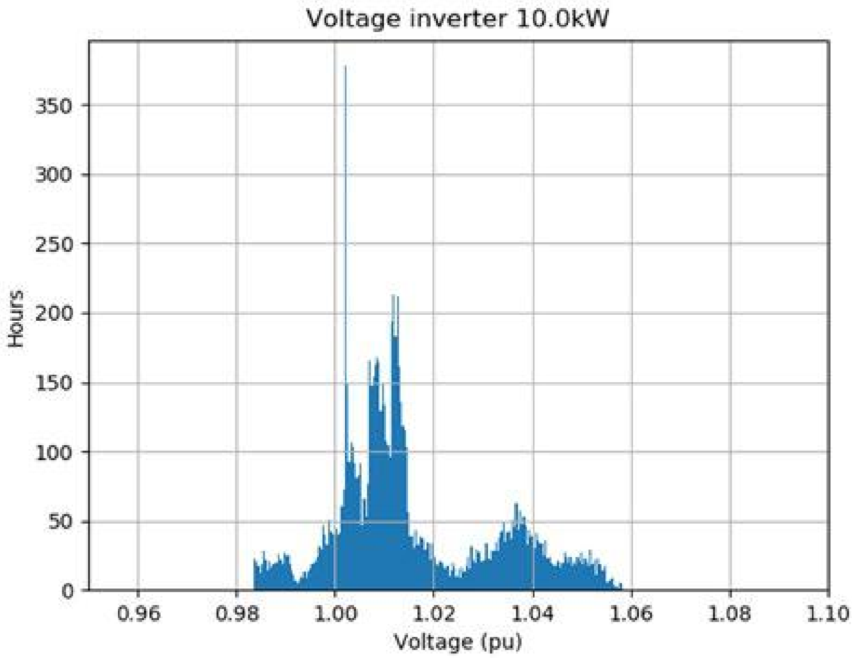


Figure 18 - Negligible Curtailment Required Above 1.054pu for 10kW Array

However, with the 15kW array installed, as seen in Figure 19, the number of intervals above 1.054pu requiring curtailment has increased significantly:

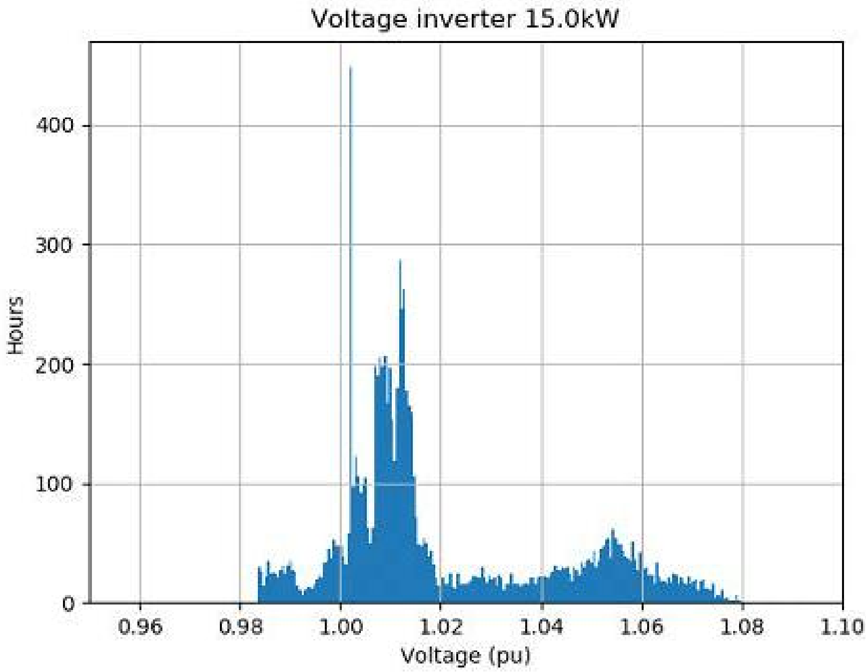


Figure 19 - Increasing Curtailment Required Above 1.054pu for 15kW Array

10.4 CONCLUSIONS

This section confirms the benefit of implementing the DDL Control Scheme on rural and remote networks and demonstrates its ability to increase the hosting capacity of these networks. The results of these site-specific studies confirm the modelling undertaken as part of the general feasibility study detailed in Section 4.

The site-specific modelling completed as part of this project shows how the DER installation size can be increased by three to five-fold under the typical rural supply scenarios modelled with only minimal curtailment of energy. The modelling also highlighted the importance of considering additional constraints beyond the point of connection — such as the 3% Voltage Change Rule or consideration of the transformer the DER is connected to (three-phase or single-phase).

In all supply situations with small customer group numbers and low group diversity, the use of single-phase transformers would increase the hosting capacity limits by opening up the entire transformer capacity to all participants rather than imposing the lower limit of a single-phase of the transformer.

11 CONCLUSIONS

This report has examined the feasibility of implementing a control scheme that applies the principles of distributed control to the challenge of increasing the DER hosting capacity of electricity networks.

The report's specific hypothesis was that the decentralised control of DER for the management of local network constraints can provide a range of benefits, in particular for regional, rural, and remote network sections. These networks were of specific focus because they capture the majority of Australia's solar irradiance while also simultaneously managing the weakest network connections, the poorest communication availability, and greatest resource constraints.

Control Scheme Feasibility

The DDL Control Scheme examined as part of this report has four key components — a network sensor, DER Controller, ONDP, and DLP. The Control Scheme as described addresses the requirements for implementing dynamic DER limits.

The OpEN project offers several frameworks for establishing dynamic DER limits and defines a set of common functions necessary for this. These include defining and improving network visibility requirements, determining constraints, and communicating operating envelopes. The DDL Control Scheme, as outlined in this document, can deliver on all of these functions.

The Newport Review undertaken as part of the Open Energy Network initiative also highlighted a number of challenges in implementing dynamic DER limits, such as Latency Cascading, Hidden Coupling, and Tier Bypassing. This report shows how the DDL Control Scheme can apply the principle of Layered Decomposition to address these challenges.

The report confirms the hypothesis that the decentralised control of DER for the management of local network constraints can provide a range of benefits, in particular for rural and remote networks. The report establishes that DER Management tasks are most effectively implemented when this occurs at the lowest level of the control hierarchy using decentralised control.

The report also confirms the DDL Control Scheme's ability to unlock the DER hosting capacity of distribution networks. The modelling completed as part of this project demonstrates that DER hosting capacity increases ranging from 120% to over 400% above the results expected from applying static limits and traditional connection management approaches are achievable with only minimal curtailment of energy. The site-specific studies also revealed the importance of considering side constraints, such as the 3% voltage change rule and the transformer characteristics and configuration (e.g. tapping settings, single- vs three-phase).

Benefits of DDL Control Scheme

The primary benefit of the DDL Control Scheme is that it decentralises the management of local network constraints for simple rural networks and, by placing the management of network constraints at the lowest control level, ensures that this control agenda is enforced.

The Scheme is also able to autonomously curtail DER capacities inside local network management constraints without requiring network models. It does this while also interfacing with slower, remote DER Orchestration platforms to facilitate other DER bid stacks, provided they do not exceed local network constraints.

The report also highlights several additional benefits that arise under the DDL Control Scheme. The use of Network Sensors improves network visibility and removes the need for up-to-date network models. Visibility of DER behaviour and current operating states (for both compliance and management) is increased. The control scheme is also robust and resilient to failure. The use of Open Source functionality and specifications for the DER controller will improve innovation, market competition, and consumer energy choice outcomes.

Next steps

The next steps for this project mirror those developed by the Open Energy Network Initiative. These will include a trial rollout of Network Sensors to improve network visibility. This will occur alongside a smaller scale trial of the use of DER Controllers and the DLP to enforce the technical limits of the network. These objectives also necessitate a small-scale trial of the ONDP described in the DDL Control Scheme, to facilitate the data exchanges involved.

Discussions with stakeholders has also outlined a range of topics that need to be adequately addressed prior to the Scheme becoming operational. These include further assessment of cyber security provisions and developing integrations into both the DNSPs' and other stakeholders' existing and emerging systems.

In the future, the project will also demonstrate the integration of both import and export limits (and thus the management of net loads) for DER sites. The intelligent controllers that are at the heart of the Network Sensor and DER Controller could also be applied both to improve forecasting (of generation and loads) and the further optimisation of the DLPs.

A further next step is to explore the co-optimisation of the operating envelopes, which are established for the management of local network constraints, with the bid stack for DER Orchestration activities. The DDL Control Scheme provides an opportunity to apply the principles of decentralised control to offer a novel solution here.

Further Work

The project has also encountered a range of topics worthy of further investigation and discussion but that were beyond the scope of the current investigation.

The capabilities of existing network modelling tools (such as PSS SINCAL, PowerFactory) need to be further developed to better deal with modelling the impact of dynamic DER limits on networks. The DDL Control Scheme does not require modelling to operate, but if a DNSP or DSO wishes to anticipate how a dynamic DER control scheme will impact their extreme network operating states and capacities, then the further development of those modelling tools will be necessary.

The benefits of dynamic DER management (hosting capacity increases, improved network utilisation, and reduced network charges for consumers) also need to be reflected in the revenue model of DNSPs. With the current revenue models, there are only very limited financial incentives (e.g. the Demand Management Incentive Scheme) to improve these. Deferring network upgrades beyond this will reduce revenues linked to asset values. New revenue models need to be developed that will adequately resource DNSPs as they fill new roles as platform facilitators, DSOs, and more.

Industry wide cybersecurity requirements also need to be better defined so that relevant decisions regarding scalability, communication protocols, technology platforms, authorisation, and system administration tasks can be made.

The 3% voltage change rule should also be reassessed, in particular for low DER penetration networks or installations where fast local DER controllers could maintain net export capacity inside the 3% rule by incorporating load control with generator curtailment. With current practices and unsaturated networks, this 3% rule will occasionally limit DER capacities to sizes that are not large enough to require curtailment under a dynamic limits control regime, removing all value of those dynamic schemes for these sites.

Interpretation of voltage supply standards should also be re-considered with a view to reducing the number of customers who experience average supply voltages in excess of 230V +6% (244V) as a new, lower network planning limit, even if the existing upper maximum limit of +10% (253V) is retained as an operational limit under extreme high export and low load events. Average supply voltages in the upper allowable range is a common outcome that limits DER hosting capacity for affected circuits and reduces the benefit of implementing any dynamic limits scheme for DER. Reducing average supply voltages so that as many customers as possible are closer to the nominal 230V level would ensure that the basic DER hosting capacity of any LV network is maximised prior to the added benefit of applying dynamic control platforms.

The OpEN's Newport Review highlighted the role of Layered Decomposition in transitioning to the smart grid of the future. However, the application of this principle has not been included in later reports and discussion papers. A more thorough investigation of how this principle could be applied, alongside communication arrangements that avoid serial communication and Latency Cascading, is warranted.

The recently released ENA Position Paper on the OpEN project (May, 2020) concludes that none of the four frameworks identified for the integration of DER into electricity networks control will produce benefits in excess of scheme costs until DER uptake reaches very high levels. This assists the justification for the DDL Scheme for two reasons. First, the DDL Scheme can be rolled out in a step-wise manner. Implementation can first focus on those network areas that already have (or are about to have) very high DER uptake and require network augmentation capital expenditure. The scheme can thus deliver benefits before high levels of DER uptake is uniform across a network. Second, the DDL Scheme's implementation actively contributes to the delivery of "least regret" actions developed as part of the OpEN Initiative by increasing network visibility. The DDL Control Scheme thus delivers immediate benefits for the management of network constraints while also preparing networks for the emerging role of the DSO at the centre of the OpEN Initiative.

12 GLOSSARY

After Diversity Maximum Demand (ADMD)	The likely maximum load on a feeder taking into account the normal operating conditions and load diversity among customers. Accounts for the fact that not all network connected equipment is operating simultaneously at full load, nor do all individual loads operate at the maximum loading level for long periods.
Decentralised or Distributed Control	A control system using autonomous controllers distributed throughout a system that operate in some manner that does not require supervision or control from a central platform to carry out some key, local control function.
Distributed Energy Resources (DER)	Small scale electrical generation and storage connected to the distribution network. Typical examples include rooftop solar and battery systems.
DER Management	The dynamic management of DER capacity limits to ensure that the local network constraints are not exceeded during DER Orchestration or at any other time. Seeks to maximise DER Hosting Capacity on the same local networks. See Section 1.3.1 for a discussion of the various related definitions.
DER Orchestration	The control of a group of DER over a potentially wide geographic area in response to wholesale market (or potentially network service) dispatch events. See Section 1.3.1 for a discussion of the various related definitions.
DER Optimisation	The co-optimisation of the DER Orchestration tasks and the priorities of DER Management (including all local network constraints).
Distribution Network Services Provider (DNSP)	Companies that build, operate, and maintain the distribution networks around Australia.
Distribution Service Operator (DSO)	An expanded technical capability of the distribution network services provider to identify and communicate network constraints and facilitate platforms necessary for the evolution and operation of the anticipated future Smart Grid at the distribution network level.
EA Technology Report	A report commissioned by AEMO and ENA as part of the Open Energy Networks project and conducted by EA Technology to investigate the high-level functionality required to bring about each of the four DSO models under consideration. In addition to examining the four proposed DSO models, the report also developed 13 key functions and associated activities required to deliver key DER Optimisation principles. The full report is available here: https://bit.ly/3bVGFdf
Frequency Control Ancillary Services (FCAS)	One of the varieties of National Electricity Market (NEM) Ancillary Services used by AEMO to control the technical characteristics of the power system. Deals exclusively with frequency control. There are two types — Regulation and Contingency. For more information on FCAS or other Ancillary Services see here: https://bit.ly/2SVNrYZ

Hidden Coupling	A challenge outlined in the Newport Review that smart grids must overcome. Describes the phenomena where two or more control schemes have partial views of the entire grid state and are operating according to individual goals and constraints. Problems will arise when these goals or constraints are in conflict.
Hosting capacity	The amount of DER that a distribution network can integrate without exceeding the technical limits of the network.
IEEE Vision for Smart Grid Controls: 2030 and Beyond	A report published by the IEEE Standards Association that raises some important points that are relevant for the current project. These include the anticipation of future use of intelligent end point controls and smart periphery.
Industrial Internet of Things (IIoT) Platform	Interconnected sensors, instruments, and controllers networked together in an industrial setting. The term builds on the common IoT framework, under which internet-connected devices that each have unique identifiers and the ability to collect and transfer data automatically, control objects, and conduct computations without requiring assistance from a central computing system or server. IIoT extends IoT frameworks to address issues of security, reliability, and scalability and more robustly than the provisions that are commonly involved for IoT schemes catering to consumer or domestic applications.
Latency Cascading or Cascading Latency	A challenge outlined in the Newport Review that smart grids must overcome. Describes the creation of excessive latencies or delays that will arise if information flows are serially directed through cascades of different organisations and/or their associated systems.
National Electricity Market (NEM)	Describes the integrated electricity system — generation, transmission networks, and distribution networks — spanning from Far North Queensland down to the western parts of South Australia. Western Australia and the Northern Territory are not part of it.
Network strength	Used to distinguish between weaker and stronger areas of the network. A site with weak supply will have a higher source impedance and a strong site will have a lower source impedance. The conductor's electrical characteristics and distance both increase the source impedance supplying the customer load (or accepting the customer DER exports). The conductor distance also affects the reliability performance of the feeder, as the reliability decreases based on the amount of conductor exposure. The longer a feeder is, the more reliability issues we also expect to encounter.
Newport Review	An international review conducted by the Newport Consortium entitled Coordination of Distribution Resources: International System Architecture Insights for Future Markets Design. Commissioned by AEMO and ENA as part of the Open Energy Networks Initiative to contribute to understanding international approaches and models to addressing the system architecture and defining the roles, responsibilities, and control coordination for real-time operation of DER. The entire report is available here: https://bit.ly/3auvS88
Observability	A control principle established in the Newport Review that describes the amount of operational visibility of the distribution network and DER that is required for effective control.

Operating Envelope

The limits within which customers' DER must operate for the safe and secure running of the network and the overall electricity system.principles. The full report is available here: https://bit.ly/3bVGFdf

Power Quality (PQ) Response Modes

As outlined in AS4777.2:2015 Grid Connection of Energy Systems via Inverters.

Smart Grid Architecture Model (SGAM)

Developed by the Smart Grid Coordination Group/Reference Architecture Working Group (SG-CG/RA) as part of the European Commission Mandate M/49012. A holistic framework for describing smart grid systems, from their functional specification right through to their architectural design. More information is available here: https://bit.ly/2xvWnwI

Smart Grid Interoperability Reference Model (SGIRM)

Provides a structured framework and architecture of domains, entities and interfaces across power systems, communications technologies, and information technologies. Control schemes can be mapped to the SGIRM framework to facilitate description, assessment, planning, and design of the scheme. Refer to IEEE 2030-2011 standard: "IEEE Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System, End Use Applications and Loads".

Tier Bypassing

A control principle established in the Newport Review that describes a problem where information flows or control instructions skip tiers or layers of the power system and opens the possibility for operational problems to be created.

Triplen Harmonics

The odd multiples of the third harmonic (h = 3, 9, 15, 21, . . .). They deserve special consideration due to the additive nature of these currents in distribution systems.

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