Project **EDGE**

Final report

VERSION 2
OCTOBER 2023

Important notice

Purpose

The purpose of this document is to synthesise and communicate to the Australian Renewable Energy Agency (ARENA) and the electricity industry key insights into Distributed Energy Resources (DER) integration to the National Electricity Market (NEM) obtained from various field tests and research activities conducted under Project Energy Demand and Generation Exchange (Project EDGE).

Project EDGE sought to understand, test and demonstrate how DER integration could work in the NEM in a way that enables efficient and secure coordination of DER to provide wholesale and local network support services within the constraints of the distribution network. The key insights in this report identify capabilities that can be replicated efficiently at scale across the NEM and core considerations for the development of policy and reform to integrate DER in a way that encourages and drives innovation and DER participation to deliver benefits to all electricity consumers. These key insights have informed the priorities identified in the report for consideration by policy makers, industry leaders, market bodies and industry participants.

This report is a synthesis of key insights from findings of various related workstreams that conducted research activities as part of Project EDGE's Research Plan developed by the University of Melbourne. The detailed findings from Deakin University's consumer research, Deloitte Access Economics' cost benefit analysis, the University of Melbourne's techno-economic modelling, lessons learnt from the Project's design and field trial activities and EY's Technology and Cybersecurity Assessment for the data exchange workstream have been published as separate reports. These can be found on AEMO's website to facilitate knowledge sharing.[1]

Disclaimer

The Project EDGE participants (AEMO, Mondo Power Pty Ltd and AusNet Electricity Services Pty Ltd) (each a Project Participant) have commissioned Ernst & Young (EY) to facilitate the production of this Project EDGE Final Report in collaboration with the Project Participants. Each of the Project Participants has collaborated with EY to ensure the quality of the information in this Project EDGE Final Report but cannot guarantee that the information, forecasts and assumptions contained it are accurate, complete or appropriate for your circumstances. This Project EDGE Final Report does not include all of the information that an investor, participant or potential participant in the national electricity market might require, and does not amount to a recommendation of any investment.

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Acknowledgements

Project EDGE received funding from ARENA as part of ARENA's Advancing Renewables Program.

The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

Each Project Participant acknowledges:

- the work of EY in supporting the preparation of this Project EDGE Final Report; and
- the support, co-operation and contribution of the other Project EDGE participants (AGL Energy, Discover Energy, Rheem and Combined Energy Technologies), vendors and consultants in providing data and information used by the Project Participants and EY to prepare this report.

Version Control

Version	Release date	Changes
Version 1	18 October 2023	N/A: Initial publication
Version 2	24 October 2023	Minor edits to clarify Figures 5, 29, and 90

Cover page image: Yackandandah, a picturesque locality three hours North East of Melbourne, Victoria – where the community has long pioneered sustainable energy solutions and actively participated in the Project EDGE trial.

1 AEMO. Nd. Project EDGE Reports. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports

ARENA summary

Activity title	Project EDGE
Contract Number	2019/ARP051
Recipient	Australian Energy Market Operator Limited
Project Participants	AusNet Electricity Services Mondo Power
Sub-contractors	Nous Group The University of Melbourne Deakin University Energy Web Foundation Opus One Solutions PXiSE Energy Solutions Ernst & Young (EY) Deloitte Access Economics **Other participants:** AGL Energy Combined Energy Technologies Discover Energy Rheem
Ref	Final Knowledge Sharing Report
Applicable time period	
AEMO contact	Nick Regan

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Glossary and use of terms

This report has been written for a broad audience. It seeks to simplify key messages by providing an Overview at the start of each chapter, but it also contains more detail within each chapter for those in the industry with a strong understanding of the more complex topics.

The Project EDGE team welcomes questions or feedback on any topics in this report, and encourages readers to engage with the team by sending an email to EDGE@aemo.com.au.

The glossary below defines key terms used throughout the report. This includes clarification on the way certain terminology is used herein; for example, when the term consumer is used rather than customer.

Active Aggregator (in the context of the EDGE trial)	Refers to the three aggregators that participated in the field tests. Namely, Discover Energy, Mondo Power, Rheem and Combined Energy Technologies (Rheem). AGL Energy (AGL) provided insights as a research participant but did not actively operate in the field tests. When discussing field test results, where the simple term aggregator is used, it also only refers to the three active aggregators unless specified otherwise (e.g. comparing AGL's experience or perspectives to the results).
Active DER	Refers to Distributed Energy Resources (DER) that actively responds to external signals to apply export and import power limits, and dispatch active and reactive power. Active DER can be turned off, ramped up or ramped down.
Active power	Refers to the total power flow (kW) exported to grid or imported from grid by an aggregator's DER portfolio within a Dispatch Interval. Active Power is an instantaneous measurement across all customer grid connection points then aggregated to a portfolio level number. It represents the 'net' flow after uncontrolled load and generation and is the telemetry corresponding to Net NMI bidding.
Aggregator	Refers to actors that represent DER from many customers, collectively managing devices to provide electricity services as a Virtual Power Plant (VPP). Aggregators can deliver multiple services on their customers' behalf, including market services to AEMO, local network services to distribution networks and hedging services to retailers. Aggregators are granted permission by customers to use their DER and data to deliver services according to the customers' preferences. Aggregators may also be registered energy retailers (i.e. retailers that operate their own VPPs).
Arming signal	Refers to the communication sent for high firmness network support services by the DNSP to an aggregator to alert the aggregator to begin preparing their LSE portfolio for the contracted service. In Project EDGE this was sent 24 hours before the start of the activation of the service.
BAU bidding behaviour	Refers to the active aggregators' general 'business as usual' bidding behaviour during benign market conditions observed during the Project EDGE field trial.
Benign market conditions	Refers to wholesale electricity market prices that are not materially high or low in terms of incentivising aggregators to coordinate a step change in their portfolio loading or generation. During the Project EDGE field trial, these were observed to be typically between -$50 and 300/MWh.
Bi-directional offer	Refers to a wholesale bid which is an offer that can include both amounts of generation and load the DER Aggregator is willing to offer in the market across 20 price bands and in 5-minute dispatch intervals. In Project EDGE a bi-directional offer represents the whole of a DER Aggregator's portfolio collectively identified under a single Dispatchable Unit Identifier (DUID).
Business to business (B2B) services	Refers to a generic industry term used to refer to defined business to business interactions between market participants and exclude interactions between a market participant and market systems.
Business to market (B2M) services	Refers to services that are transacted between market participants and the relevant market operator.
Central dispatch process	Refers to the central process in the national electricity market (NEM) that AEMO runs to match supply and demand (in 5-minute intervals across 5 regions). The central dispatch process aims to efficiently match electricity supply to demand while ensuring the power system will remain secure. The process includes managing bids and offers, scheduling and dispatch of generators, determining the market (clearing) spot price, monitoring network constraints and transmission power flows, and financially settling the market.
Consumer	Refers to the broader population of electricity customers, regardless of whether they have DER or not.
Controlled generation	Refers to the total generation and/or battery discharge activity of the aggregator's DER portfolio. It only includes DER generation under the control of the aggregator. It does not include uncontrolled generation (such as passive DER) that is not actively controlled by the aggregator.
Controlled load or controllable load	Refers to the sum of load and/or battery charging activity of the DER aggregator's DER portfolio. It only includes DER loads under the control of the DER aggregator. It does not include uncontrolled loads such as household appliances.
Controlled power	Refers to the total power flow (kW) from all controllable DER in the aggregator's portfolio (controlled generation plus controlled load) within a Dispatch Interval. Controlled power is an instantaneous measurement across a common DER measurement point at each customer site then aggregated to a portfolio level number. It represents the gross DER activity excluding uncontrolled load and generation and is the telemetry corresponding to Flex Bidding.
Coordinated DER	Refers to DER that is predictable, visible and operable. This can include DER that can respond to an operational signal such as: • A DOE from a DNSP or a dynamic export limit from a retailer • A control signal from a VPP participating in the wholesale energy market with visibility and/or dispatchability capabilities.
Curtailment	Curtailment is the deliberate reduction in electricity output below what could have been produced in order to balance energy supply and demand or due to transmission constraints.
Customer	Customer refers to persons being recruited, or acquired, by a DER Aggregator or retailer, or in the context of a person who forms part of a connection agreement with a DNSP.
Data hub	Refers to digital infrastructure allowing data exchange between parties.

DER marketplace	Refers to the trial environment designed and created to undertake Project EDGE. As the project is seeking to inform how DER could be integrated into existing electricity markets and frameworks (adapting where necessary), rather than the establishment of a separate marketplace for DER, any references relate to a two-sided marketplace which integrates DER into the NEM.
DER capacity	Refers to the capacity in (kW) available to DER for power generation (export) or load (import) at a given point in time. It differs from DER nameplate capacity in that it refers to the capacity available for a particular dispatch interval rather than the DER's full potential capacity.
DER nameplate capacity	Refers to the maximum amount of energy a DER device is able to either generate or load (consume) as listed in the product specification by the manufacturer. For example, rooftop PV with a DER nameplate capacity of 5kW could generate a maximum of 5kW at any given time. For DER that are controlled loads this is the rated electrical load capacity.
Dispatch interval	Refers to the time period of 5 minutes that the NEM supply demand balancing optimisation works to. Market prices and dispatch instructions are linked to specific dispatch intervals. The dynamic operating envelopes used in EDGE are also calculated to apply for a dispatch interval
Dispatch target	Refers to the energy target an aggregator's portfolio must reach by the end of the dispatch interval. It is issued within a dispatch instruction.
Distributed Energy Resources (DER)	Refers to distributed level resources, which produce electricity or actively manage consumer demand. The term Consumer Energy Resources (CER) has emerged since the beginning of the project to refer to consumer-owned DER. However, this report uses the term DER to cover all assets connected to the distribution network, both consumer and non-consumer owned or leased.
Distributed PV Contingency (DPV-C)	Refers to a power system security risk of distributed PV unexpectedly disconnecting in large volumes at the same time as a large generator, that can occur during minimum system load periods of concurrently high rooftop solar PV exports and low operational power system demand.
DOE breach	Refers to performance that did not conform to the dynamic operating envelope allocated to a particular customer connection point for a relevant Dispatch Interval. This was the definition used for analysis of the active aggregators' performance in the Project EDGE field trial. In the trial, a deviation from the DOE of 0.01kW or more in any Dispatch Interval constituted a breach. The use of an absolute value based definition of a breach (instead of a graded approach based on percentages and frequency of deviation for example) in the Project EDGE trial results analysis is not meant to suggest that this approach is necessarily suitable for operational use.
Dynamic network prices (DNPs)	Refers to an arrangement whereby the DNSP calculates cost reflective pricing for network capacity at different time intervals within a day or across several days. This approach potentially allows for aggregators and DER customers to shift their controllable load and generation activities to times of lower network costs. This approach was not trialled in Project EDGE but could be applied concurrently with dynamic operating envelopes to optimise allocation of network capacity for DER.
DNSP	refers to a Distribution Network Service Provider acting in their current role of owning, controlling or operating a distribution system as defined under the National Electricity Rules (NER).
DSO	The term Distribution System Operator is defined in the NER as an entity registered with AEMO that is responsible for controlling or operating a portion of the distribution system. In this report, DSO is used when discussing potential enhanced future roles, responsibilities and capabilities that a DNSP could develop to support and realise the value of large-scale integration of DER into the NEM. This includes capabilities such as calculating Flexible Export Limits, DOEs, procuring Network Support Services and dynamic network operations.
Dynamic export limit	Refers to signals sent by retailers to customers' DER or aggregators to incentivise a reduction in the customer exports from a reduction in DER controlled generation or an increase in controlled load, to limit a retailer's negative wholesale price exposure. This is distinct from the flexible export limits that DNSPs send to indicate the technical operating limits of the local distribution network.
Dynamic operating envelope (DOE)	Refers to the limits on the amount of electric power that a customer can import from and export to the distribution grid at a point in time, where these limits (operating envelope) can vary for each dispatch interval according to the prevailing grid conditions (i.e. are dynamic). DOEs represent the technical operating limits of the local distribution network in contrast to static limits that are more conservatively determined and set at the time of connection to the distribution grid.
Efficiency of DOE	Refers to the amount of power the DOE enables to flow through the distribution network compared to the true network limit (absolute limit). The more accurate and closer to the true network limit (i.e. the less difference between the true network limit and the DOE), the more efficient it is. It is also referred to as DOE efficacy.
Fleet	Refers to the entire collection of registered DER devices that are under an aggregator's control. The fleet forms the aggregator's portfolio, which is its Virtual Power Plant (VPP).
Flex bidding	Flex bidding is a mode of bidding tested in Project EDGE whereby the definition of power quantity (kW) submitted in the Bi-directional Offer represents the sum of controllable DER devices (load and/or generation, not individual devices) across the aggregator's registered portfolio of NMIs. It is estimated at a real or virtual common measurement point of controllable devices at each customer site and then aggregated to a portfolio level number. It represents an Aggregator's intended gross DER activity excluding uncontrolled load and generation. Controlled Power is the corresponding actual telemetry measurement.
Flex DOE	Refers to a DOE applied at the flexible device level (assigned to controllable load and generation only) and excluding native, uncontrolled load.
Flexible export limit (FELs)	Refers to export limits calculated by the DNSP at a connection point based on the hosting capacity and power flows at that point on the network at a given time. FELs refer to the ability to vary export limits over time and location based on the available capacity of the local distribution network. FELs refer to export, while DOEs refer to both export and import.
Improved network hosting capacity	refers to additional hosting capacity enabled by DOEs, allowing increased export (or import) of electricity at a connection point. The improved network hosting capacity can be utilised by DER.
Local Services Exchange (LSE)	refers to the interface to facilitate visible, scalable and competitive trade of DER-based Network Support Services for local network constraint management.
Lost DER capacity	Lost DER capacity is used in the context of comparing outcomes from different DOE calculation approaches. It refers to the difference in improved network hosting capacity between different calculation approaches.
LSE portfolio	refers to a subset of an aggregator's DER portfolio used to provide network support services. Since network support services are needed for local network areas, an LSE portfolio comprises one or more NMIs within the same constrained local network area. As such, an aggregator can have multiple LSE portfolios within its overall DER portfolio. These may be organised within an Aggregator's own systems and/or registered with a DSO.
Multi Criteria Analysis (MCA)	refers to an analysis process that scores and rates options against multiple criteria. MCA provides a way of analysing alternatives against outcomes that are important for decision-makers, but which cannot be readily quantified and monetised.
Network hosting capacity	refers to the maximum power flows that can be securely managed on a segment of the electricity network. This is defined by the ratings of network assets like transformers and power lines and the power quality requirements that apply. Hosting capacity determines how much load or generation a given connection point on the network may be able to carry. Spare network hosting capacity that is not servicing customer essential electrical service loads can be utilised by DER.
Network support service (NSS)	refers to energy services that a DNSP or DSO procures to manage network constraints. Examples include an increase or decrease in demand, or voltage management services.
NMI DOE	refers to a DOE applied at the individual connection point with the distribution network (the National Meter Identifier (NMI)), allocating import/export limits at the site (includes all controllable and uncontrollable devices.
Net NMI bidding	Net NMI bidding is a mode of bidding tested in Project EDGE whereby the definition of power quantity (kW) submitted in the Bi-directional offer represents the sum of net connection point power flows (controlled and uncontrolled load and/ or generation, not individual devices) across the aggregator's registered portfolio of NMIs. It is estimated at a real or virtual common measurement point close to the grid connection point at each customer site and then aggregated to a portfolio level number. It represents an Aggregator's intended net DER activity including uncontrolled load and generation. Active Power is the corresponding actual telemetry measurement.
Non-network solutions	refers to solutions to alleviate network constraints and boost reliability during peak demand period, as an alternative to network augmentation solutions (building additional network hosting capacity). Solutions can include demand-side management or local generation. It is analogous to network support services. The distinction in this report is that network support services is used in the context of an additional revenue opportunity aggregators could access. Whereas non-network solutions is a regulatory term and could be provided directly from a customer (e.g. a commercial and industrial customer) rather than through an aggregator. The regulatory terms means an option by which an identified network need can be fully or partly addressed other than by a network option. A network option is a means by which an identified need can be fully or partly addressed by expenditure on a distribution asset (augmentation), which is undertaken by a DNSP.
Notice signal	refers to the communication sent for network support services by the DNSP to an aggregator to alert the aggregator the impending start of the activation of the service. For Project EDGE, this was sent half an hour before the start of the activation of the service.
Passive DER	refers to DER that is not enabled to respond to external signals. This is forecast as uncontrolled load and/or generation.
Portfolio	refers to an aggregators' entire fleet of registered DER devices under its control that forms its Virtual Power Plant (VPP).
Portfolio telemetry	refers to the actual measurement of total power flow for all sites and controllable DER registered in an aggregator's portfolio (also referred to as DUID level) and are instantaneous measurements. In Project EDGE portfolio telemetry files provided Active Power, Controlled Generation, Controlled Load and energy stored (kWh).
Power system security	Power system security refers to: • The technical parameters of the power system such as voltage and frequency. • The rate at which these parameters might change. • The ability of the system to withstand faults. The power system is secure when technical parameters such as voltage and frequency are maintained within defined limits. To maintain frequency the power system has to instantaneously balance electricity supply against demand.
Project Participants	Refers to AEMO, AusNet Services and Mondo Power.
Reliability	Refers to when the power system has enough generation, demand response and network capacity to supply consumers with the energy that they demand with a very high degree of confidence. This requires: • Well-functioning electricity spot and contract markets providing clear price signals, along with forecasts and notices from the system operator, AEMO, backed up by policy certainty from governments. This gives market participants incentives and information to supply generation and demand response when and where it is needed. • A reliable transmission and distribution network (the poles and wires). • The system being in a secure operating state, that is, able to withstand shocks to its technical equilibrium.
Scheduled generation	Refers a to generator that can be registered with AEMO as 'Scheduled' and as such must be considered in the NEM central dispatch process. In the NEM, Scheduled refers to a generating system with an aggregated nameplate capacity over 30MW and attracts a host of corresponding performance standards. AEMO has the ability to control scheduled resources if required for system security and it receives real-time data from the generators.[2]

Semi-scheduled generation	Refers to generating systems with intermittent output (such as wind and solar farms) and an aggregate nameplate capacity of 30MW, or more. AEMO can constrain down semi-scheduled generation if required for system security and it receives some real-time data on performance.
Social licence	Social licence is defined by Energy Consumers Australia as the permission provided by consumers to government or institutions to control their DER system, above and beyond that required by law. In this report, it refers specifically to customers' support and trust that enables their privately-owned DER to be managed in a way that delivers additional benefits for them, the power system and all consumers.
Spare hosting capacity	Refers to the network hosting capacity to support electricity exports and imports. Referred to as 'spare' in terms of it being additional to the capacity needed to support customer essential electrical service loads.
Unallocated capacity	Refers to the term used in research conducted by the University of Melbourne for Project EDGE and refers to the DER rated capacity (e.g. the amount of power a DER could provide) that was prevented from exporting as it was not allocated any network hosting capacity via DOEs.
Uncontrolled load	Refers to consumers' essential electricity service. It is generally consumption from everyday electrical appliance and use. It also includes passive DER generation which might offset load.
Value stack	Refers to offering a variety of services using the same DER portfolio response, which allows an aggregator to receive multiple value streams. These multiple value streams are known as value stacking because the aggregator's portfolio provides benefits to customers, the network, and the market (depending on the services). For example, an aggregator using the same DER within its portfolio to provide wholesale electricity services and network support services.
Vehicle-to-grid (V2G)	Refers to the concept of discharging an EV battery to serve a secondary purpose (other than mobility for that EV). Specifically, this refers to discharge capability that provides wider system services.
Virtual Power Plant (VPP)	Refers to an aggregation of small-scale Distributed Energy Resources (DER), such as decentralised generation (e.g. rooftop PV), storage and controllable loads, coordinated to deliver large-scale services for power system and distribution network operations and electricity markets. VPPs are operated by aggregators and are synonymous with aggregator/DER 'fleet' and 'portfolio'.

2 AEMO (Australian Energy Market Operator). N.d., Visibility of the power system factsheet. https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/0DE87F5ADD5D42F7B225D7D0799568A8.ashx

Acronyms and abbreviations

Acronym	Full name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	AGL Energy
API	Application Programming Interface
ARENA	Australian Renewable Energy Agency
Augex	Augmentation Expenditure
B2B	Business-to-business
BAU	Business As Usual
BIA	Business Impact Analysis
Capex	Capital expenditure
CBA	Cost benefit analysis
CER	Consumer Energy Resources
CESS	Capital Expenditure Sharing Scheme
CL	Controlled Load
CLASS	Customer Load Active Support Services
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
CISP-AUS	Common Smart Inverter Profile for Australia
DER	Distributed Energy Resource(s)
DERMS	Distributed Energy Resources Management System
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
DNP	Dynamic Network Price
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
DPV-C	Distributed PV Contingency
DSO	Distribution System Operator
DUID	Dispatchable Unit Identifier
EBSS	Efficiency Benefit Sharing Scheme
ENA	Energy Networks Australia
ESB	Energy Security Board
EV	Electric vehicle
EY	Ernst & Young
FCAS	Frequency Control Ancillary Services
FEL	Flexible export limit
FRMP	Financially responsible market participant
FTA	Flexible Trading Arrangement
FTM	Flexible Trader Model
GW	Gigawatt
HV	High voltage
ISP	Integrated System Plan

Acronyms and abbreviations (cont..)

kVA	Kilovolt-amps
kW	Kilowatt
kWh	Kilowatt Hour
LoR	Loss of Reserve
LSE	Local Services Exchange
LV	Low Voltage
MCA	Multi-criteria Analysis
MSL	Minimum System Load
MW	Megawatt
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Meter Identifier
NSS	Network support services
OEM	Original equipment manufacturer
OpEN	Open Energy Networks Project
Opex	Operating expenditure
PV	Photovoltaic
Repex	Replacement expenditure
RERT	Reliability and Emergency Research Trader
RIT-D	Regulatory investment test for distribution
RRP	Regional reference price
SAPN	SA Power Networks
SCED	Security Constrained Economic Dispatch
TNSP	Transmission Network Service Provider
UK	United Kingdom
UoM	University of Melbourne
V2G	Vehicle-to-grid
V2X	Vehicle-to-everything
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WDRM	Wholesale Demand Response Mechanism

Executive summary

Project EDGE (Energy Demand and Generation Exchange) was a research trial, funded by the Australian Renewable Energy Agency (ARENA), for which the Project Participants – the Australian Energy Market Operator (AEMO), AusNet Services (AusNet) and Mondo – established an off-market, proof-of-concept field trial to test various ways of integrating Distributed Energy Resources (DER) into the National Electricity Market (NEM).

There were three additional participants. Discover Energy (Discover), an energy retailer, and Rheem and Combined Energy Technologies (Rheem), a behind-the-meter aggregator, actively operated in the field trial with their own systems and customers. AGL Energy (AGL), an established Virtual Power Plant (VPP) retailer, also provided insights as a research participant.

This final knowledge sharing report aims to synthesise the many learnings and insights from Project EDGE across its three-year duration. Although it is necessarily a long report, many sections are relatively brief and reference other knowledge sharing reports that capture more detail on associated topics. Recognising that some stakeholders will prefer a short summary, this report is supplemented by a webinar presentation pack that aims to summarise the key messages in a more visual format.[3]

The research approach has included literature reviews, specialist modelling/analysis, practical evidence from the field trial and extensive stakeholder engagement to produce evidence-based and practical insights. This report contains the key findings from Project EDGE for consideration by industry and policy makers in ongoing DER integration reform activities that aim to maximise the benefits of DER for all consumers.

Coordinated DER at scale can accelerate the net zero transition[4]

The NEM is experiencing a rapid transformation, driven by Australia's accelerating uptake of DER. AEMO's 2022 Integrated System Plan (ISP), which provides a whole-of-system roadmap for ongoing development of the NEM, anticipates a 'decentralisation, digitalisation and democratisation' of the NEM by 2050 under the step change scenario.[5] Stakeholders engaged in the development of the ISP identified the step change scenario as the most likely scenario.

Figure 1 illustrates the forecast scale of this change up to 2050:

- Over 100 gigawatts (GW) of DER are expected to be connected to the NEM, including an increase from approximately 15GW of aggregate residential rooftop photovoltaic (PV) capacity to 69GW, representing 40% of total NEM installed capacity (left side of Figure 1).
- Over 75% of storage capacity could be distribution connected (right side of Figure 1).
- Coordinated DER storage (31GW, including 7GW of vehicle-to-grid (V2G) electric vehicles (EVs)) may represent almost half of total dispatchable capacity.

DEFINITION

Coordinated DER storage

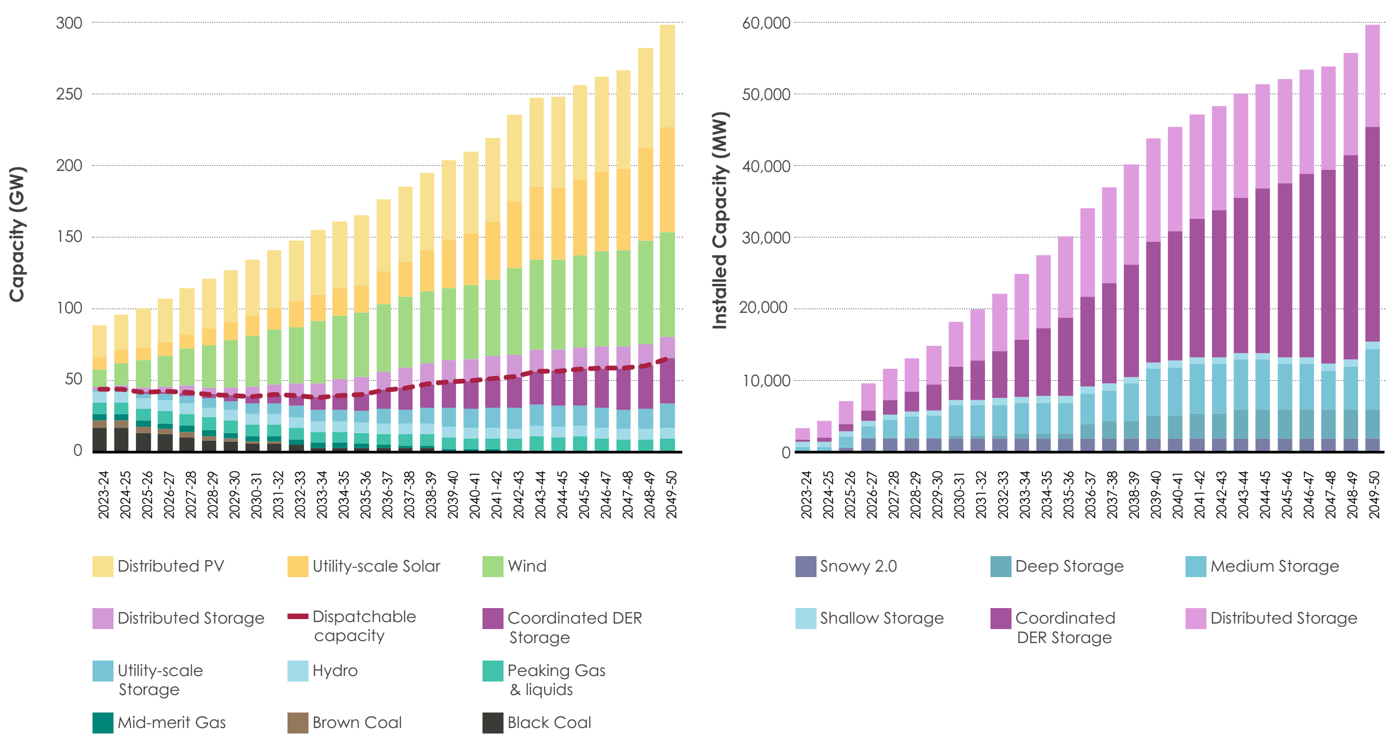
Coordinated DER storage is integrated into, and responsive to, power system and market needs, and can be forecast.

3 AEMO. N.d., Project EDGE Webinars. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-webinars

4 In 2022, the Australian Government passed the Climate Change Act to double the target for emissions reductions by 2030 and set the goal of reaching net zero by 2050. To facilitate that, the Government has established a suite of policy strategies to fast-track the energy transition. Powering Australia is a comprehensive plan focused on reducing power bills and reducing emissions by boosting renewable energy. Strategies includes Rewiring the Nation to upgrade Australia's energy grid to enable the growth of renewables in the NEM. It also includes the National Electric Vehicle (EV) Strategy to encourage a rapid increase in EV uptake, including establishing supporting EV infrastructure. The National Energy Performance Strategy aims to provide a long-term framework for demand-side action. https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks

5 AEMO. 2022, 2022 Integrated System Plan; p 9; p 54. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

Figure 1 | 2022 ISP most likely scenario: generation mix (left), storage mix (right)



Source: AEMO, 2022 Integrated System Plan[6]

This anticipated scale of DER uptake presents both challenges and opportunities for the power system, electricity market and consumers.

DER coordination represents a significant opportunity to accelerate the pace of the transition to net zero through utilising the flexible capabilities of DER in a way that works for DER owners and delivers a more affordable, secure and reliable power system for all consumers.

As the energy transition unfolds, new DER coordination capabilities can support essential power system requirements, such as predictability and dispatchability:[7]

- Distribution Network Service Providers (DNSPs) publishing Dynamic Operating Envelopes (DOEs) will enable market visible coordination of rooftop PV to remain within distribution network and broader power system limits while allowing much more efficient utilisation of the existing grid for two-way energy flows.
- As coordinated DER storage reaches material scale through VPPs, these resources will need to be integrated progressively into the wholesale market dispatch process. The consultation paper for the Integrating price-responsive resources into the NEM rule change outlines the following benefits:

1. **Dispatch costs in the NEM** — knowing when these resources can be used to reduce demand (particularly at higher cost times), improves demand forecasting and reduces the amount of higher priced resources that AEMO dispatches to meet demand
2. **Energy prices in the NEM** — by more accurately matching supply and demand, the cost of energy would be more efficient, potentially reducing wholesale spot prices
3. **Security of supply in the NEM** — by reducing the need for additional, potentially more expensive generation and dispatchable resource reserves to balance the market, system security will be achieved at lower cost
4. **Reliability of supply in the NEM** — the ability to schedule these available resources could improve planning and the use of lower-cost lower-emission generation and lower market intervention costs
5. **Operation of distribution and transmission networks** — longer-term accurate forecasts would improve network investments and planning, reducing network costs to consumers.[8]

These potential benefits demonstrate the opportunity provided by coordinated DER at scale to facilitate an efficient and timely transition to net zero while maintaining network security and reliability, and building a power system for the future that benefits all consumers.

The ISP modelling assumes that changes required to coordinate DER at scale occur, but if existing low levels of DER visibility and coordination stay the same, DER at this scale would have a material impact on NEM dynamics and system security in two key ways:

- A five-fold increase in customer owned rooftop PV will reduce operational demand levels below secure thresholds during periods of peak solar generation and AEMO would be required to take actions to secure the power system, such as emergency disconnection of entire distribution feeders operating in reverse flow.[10]
- The amount of DER storage operating dynamically may cause material swings in the supply-demand balance that could impact system security and reduce the accuracy of AEMO's operational forecasting, which would increase system costs for all consumers.

Action must be taken now to design and implement enduring solutions to integrate and coordinate DER within the NEM, since:

- AEMO's 2023 Electricity Statement of Opportunities (ESOO) sensitivity modelling found reliability risks increase if demand side coordination does not materialise (increasing the risk of load shedding in peak demand events).[11]
- Insufficient action will result in higher costs for consumers just as they are electrifying their lives by transitioning to EVs, replacing gas-fuelled appliances with electric alternatives and becoming more dependent on affordable and reliable electricity.

Looking simply at the potential for avoided costs of duplication from investment in large-scale resources: if 20% of the projected coordinated DER storage in the 2022 ISP step change scenario were to be replicated through investment in grid-scale shallow storage each year to 2040, the cumulative capital cost would be approximately \$1.8b, rising to approximately \$4.4b if 50% of the capacity needed to be replicated over that same period.[12]

This indicates that a material consumer cost impact could potentially be avoided through effective integration of DER into market processes. Previous studies have modelled the issue of DER integration more broadly, demonstrating substantial net benefits associated with greater coordination of these resources. These include avoided costs along the electricity supply chain such as generation investment, system balancing, and network investment, with associated reductions in consumer costs.[13]

Project EDGE tested mechanisms to enable DER coordination at scale

Project EDGE examined different approaches to delivering four essential DER integration functions, in addition to examining how consumer needs and preferences can be met to enable their DER to be utilised in these functions:

- **Wholesale market services:** DER providing scheduled wholesale electricity services at scale
- **Local constraints:** Ensuring local power flows remain within distribution network capacity limits using Dynamic Operating Envelopes (DOEs)
- **Efficient data exchange:** Secure, efficient, and scalable ways to exchange vast amounts of data among many industry participants to facilitate DER service delivery and secure grid operation. In Project EDGE, this function was enabled by each participant connecting to a DER data hub capability
- **Network support services:** DER providing services that enable more efficient use of distribution networks and facilitate network investment deferral.

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6 AEMO. 2022, 2022 Integrated System Plan, p 9; p 54. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

7 AEMO. 2020, Power System Requirements July 2020 Reference Paper. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf

8 AEMC (Australian Energy Market Commission). 2023, Consultation Paper - National Electricity Amendment (Integrating Price-Responsive Resources Into the NEM) Rule: National Energy Retail Amendment (Integrating Price Response Resources Into the NEM) Rule - 3 August 2023. https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

9 Operational demand is the demand for energy from the NEM.

AEMO. 2021, Demand Terms in EMMS Data Model. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

10 Reverse flow means the feeder is acting as a net generator supplying power back to the grid through exports from customer rooftop solar and/or battery systems.

11 AEMO. 2023, 2023 Electricity Statement of Opportunities: August 2023, p 95. https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en

12 AEMO. 2023, Electricity Rule Change Proposal: Scheduled Lite January 2023, p 37. https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

13 Baringa. 2021, Potential network benefits from more efficient DER integration. https://www.datocms-assets.com/32572/1629948077-baringaesbpublishable-reportconsolidatedfinal-reportv5-0.pdf

Graham, P.W., Brinsmead, T., Spak, B. and Havas, L. 2019, Review of cost-benefit analysis frameworks and results for DER integration: Input to AEMO and ENA Open Energy Networks Project. https://aemo.com.au/-/media/files/electricity/nem/der/2019/oen/csiro_cbareviewreport_13-05-2019.pdf?la=en

NERA Economic Consulting. 2022, Valuing load flexibility in the NEM: Report prepared for ARENA. https://arena.gov.au/assets/2022/02/valuing-load-flexibility-in-the-nem.pdf

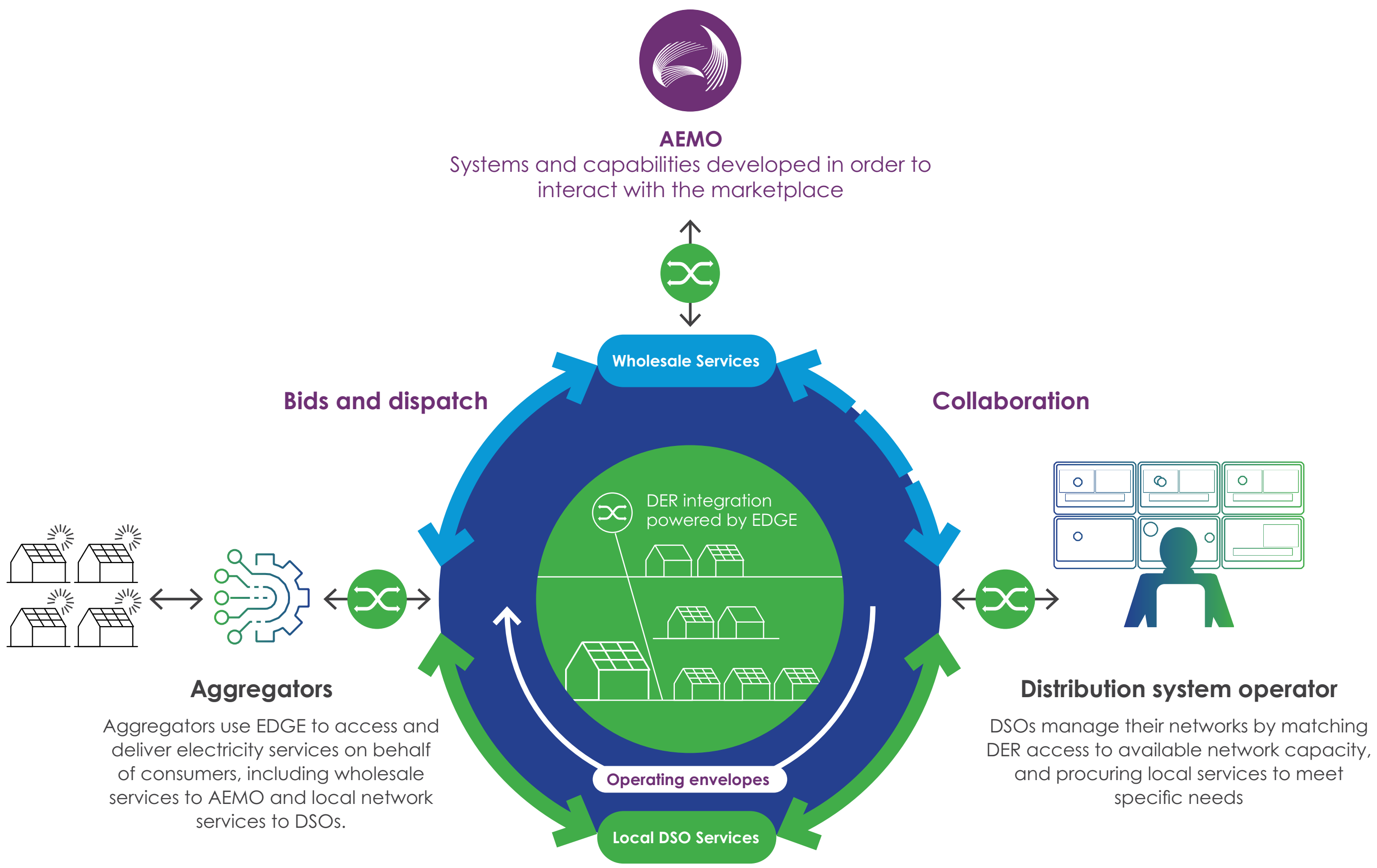
These functions represent the end-to-end journey of DER participation in electricity networks and markets. The testing of this lifecycle builds on industry collaboration in the Open Energy Networks[14] program and, along with the exploration of consumer needs and preferences, is a unique element of Project EDGE to provide insights that inform approaches for integrating DER at scale into the NEM.

Identifying how to achieve efficient DER integration and optimisation across different value streams[15] is a complex, multi-faceted topic that involves many different aspects of the energy industry. Project EDGE trialled an evolution of the NEM to one where price-responsive DER can be efficiently integrated into market arrangements rather than needing a separate electricity marketplace for DER.

While Project EDGE tested these concepts in an off-market environment for 333 days (using real forecast and actual market prices for Victoria), the concepts can largely be leveraged by the relevant NEM frameworks including roles and responsibilities in the NER, the wholesale electricity spot market and central scheduling and dispatch. Project EDGE did not test all the functions and frameworks associated with the wholesale market, such as registration and settlement.

The three active aggregators, AusNet and AEMO successfully built and operated systems and processes to coordinate, in real time, the functions needed for DER system and market integration. The functions included DOEs, DER fleet forecasting, coordination and visibility, and scalable data exchange between multiple industry actors.

Figure 2 | Conceptual view of how DER could be integrated into the NEM as tested by Project EDGE



14 AEMO and ENA. 2019, Open Energy Networks Interim Report: Required Capabilities and Recommended Actions. https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

15 In this report, the use of the term value streams refers to the various available potential revenues. These include energy arbitrage, market ancillary services, local network services, and business-to-business agreements (e.g., between aggregators and retailers).

Project EDGE addressed the complexity of exploring the multiple elements associated with DER integration by structuring the project around seven core research questions and 21 hypotheses. The National Electricity Objective (NEO) served as the starting point for a design thinking approach to formulating the research questions, hypotheses and field trial design.[16] The research questions and hypotheses are articulated in an independent research plan developed by UOM.[17]

Several vendors contributed to delivery against the research plan through robust, specialist research and analysis:

- Deakin University (Deakin) conducted a comprehensive customer insights study to identify motivations and barriers for investing in DER and participating in VPPs.
- Deloitte Access Economics and Energeia conducted a cost benefit analysis (CBA) to quantify the net economic benefits of integrating DER into the NEM and determine whether it would be in the long-term interests of electricity consumers.
- Ernst & Young (EY), in collaboration with Project and trial participants, analysed field test data to test related hypotheses, and supported Project Participants in developing knowledge sharing and stakeholder engagement materials.
- University of Melbourne (UoM) developed algorithms and conducted techno-economic modelling to test operating envelope design.

Project EDGE is one of four current ARENA supported DER integration pilot projects and trials that are demonstrating various functions to support the transition to a high DER power system. The other three are:

- Project Symphony, which is piloting DER delivering wholesale and network support services in Western Australia[18]
- Project Edith, which is testing dynamic network prices (DNPs) in New South Wales (NSW)[19]
- Project Converge, which is testing the concept of Shaped Operating Envelopes in Canberra.[20]

Each of these trials is building on the lessons of previous trials that successfully demonstrated aspects of DER integration or specific functionalities.[21] Each project is contributing important learnings to inform evidence-based decision making by industry leaders and policy makers on the DER integration approaches that most align to the NEO.

Project EDGE has identified a practical framework of roles and market configurations that have the flexibility to facilitate new innovations as industry needs evolve and other DER trials prove successful.

Key findings

Each chapter in this report discusses detailed insights across the full breadth of topics Project EDGE has examined. This section synthesises the overarching insights and key findings from the project.

The key findings have been summarised into a Project EDGE DER Integration Framework, shown on the next page. This is not an exhaustive framework; rather, it is intended to highlight the key learnings from the project in a structured way.

Each finding is necessarily succinct to fit onto a page. Further context/detail can be found in the relevant Chapter/section and associated reforms, as referenced.

A full list of key insights and implications, including areas that could be given priority for consideration by industry, is provided in the table following this Executive Summary.

16 The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
- Price, quality, safety and reliability and security of supply of electricity
- The reliability, safety and security of the national electricity system.

AEMC. N.d., National Energy Objectives. https://www.aemc.gov.au/regulation/neo

17 UOM. 2022. Project Edge Research Plan. https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35

18 AEMO. N.d., Project Symphony. https://aemo.com.au/initiatives/major-programs/wa-der-program/project-symphony

19 Ausgrid. N.d., Project Edith. https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith

20 Evoenergy. N.d., Project Converge. https://www.evoenergy.com.au/project-converge

21 DEIP (Distributed Energy Integration Program). 2022, DER Market Integration Trials: Summary Report September 2022. https://arena.gov.au/assets/2022/09/der-market-integration-trials-summary-report.pdf

Figure 3 | Project EDGE DER Integration Framework

Project EDGE key findings

This DER integration framework represents a structured way to present the key findings from Project EDGE.

The Project EDGE roles and market configurations have the flexibility to facilitate new innovations as industry needs evolve and other DER trials prove successful.

Associated Reforms (AR)

1. AEMC Metering Review
2. ESB Interoperability Directions Paper
3. AER Flexible Export Limits
4. DEIP DOE Working Group Outcomes Paper
5. AEMC CER Technical Standards Review
6. AEMC Integrating Price Responsive Resources into the NEM
7. AEMC Unlocking CER Benefits Through Flexible Trading
8. Incorporating emissions reduction into the national energy objectives
9. NEM Reform Implementation Roadmap – DER Data Hub and Registry Services
10. NEM Reform Implementation Roadmap – Distribution Local Network Services

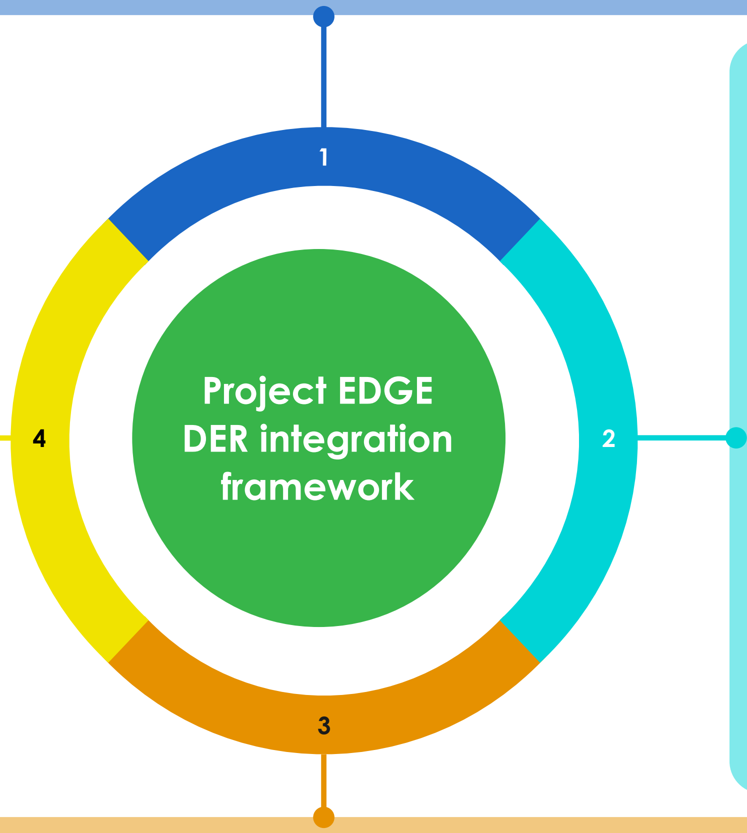
1. Consumer-centric

- Greater coordination of active DER in the NEM via Project EDGE arrangements can result in an incremental value to all consumers of up to $5.15b in the most likely scenario (Chapter 3)
- Customers are optimistic about VPPs but financial and trust barriers need to be addressed (Chapter 2)
- Enable consumer choice: Consumers should be able to choose whether or not to join a VPP, and be confident they will be better-off by participating in VPPs.
- Simple customer experiences and easy to understand communication is critical to customer retention (Chapter 2)
- Greater DER participation = greater value: Before joining a VPP customer should be able to access value through enrolling in dynamic connections, market active solar or DER responsive network tariffs. Joining a VPP enables further value and greater emissions reductions from system or network support services (NSS). (Section 6.3.2)
- Enable access to data: Customers, and service providers they nominate through explicit consent, should have access to real time data so that they can optimise how their resources are operated. (Section 2.3.5, ARs 2, 5, 7)
- Enable DER interoperability: Open communication standards and the ability to send control signals locally (e.g. for onsite home energy management system to communicate with any DER) will enable greater customer choice of service providers. (Section 2.3.5, ARs 2, 5)
- Customer consent records: Customer consent for who is optimising their resources (either to adhere to DOEs or to deliver services) must be recorded.

4. Clear Roles & Responsibilities

DER value driven by clear, proven, customer-centred roles:

- DER optimisation: Aggregators with explicit customer consent are responsible for optimising customer resources to meet their needs and deliver additional value through supporting network or power system needs. (Chapter 8)
- Distribution network optimisation: DNSPs are responsible for optimising their network operations and ensuring power flows on their network to remain within secure limits.
- Whole of system optimisation: AEMO is responsible for power system security and wholesale market optimisation & dispatch.
- Common data exchange infrastructure operations: If a DER Data Hub is established as common data exchange infrastructure industry must decide who is best placed to own, operate, govern and maintain/ update it. (Chapter 6, AR 9)
- Local Network Support Services (NSS) platforms: Project EDGE found that DNSPs can be responsible for their own NSS platforms, as long as standardisation is achieved across DNSPs. (Section 7, AR 10)



2. Secure & Reliable

- Dynamic Connection Agreements (DCAs): Together with associated Dynamic Operating Envelopes (DOEs), DCAs will be a critical mechanism to enable rooftop PV to scale fivefold (in line with ISP forecasts) whilst keeping power flows and VPP operations within secure network and power system limits. (Chapter 4, ARs 3, 4)
- DOEs should start simply and progress in sophistication over time aligned to network needs (Chapter 4, ARs 3, 4)
- DOE & DER technical standards compliance: Compliance to DOEs and DER technical standards will enable AEMO/DNSPs to better secure the power system for consumers. A DER Data Hub may support the compliance process with traceability and visibility of DER settings and firmware upgrades. (Section 6.3.2, AR 5)
- DER Cyber Security: Most aggregators focus on protecting their systems from cyber risks but there is a gap in capabilities that assume compromise. There is broad support for DER-specific cyber security standards to be implemented. (Section 6.3.5.2, ARs 2, 5)
- Compensatory controls: Collaboration between DNSPs, VPPs and AEMO is required to agree consistent processes for compensatory controls to coordinate DER operations, including during emergencies. (Section 6.3.5.3, AR 4)

3. Efficient & Affordable

Dynamic Connection Agreements

- Mass adoption can deliver savings for all: CBA found mass DOE adoption and DER participation enable most savings as DER displaces more costly resources (Chapter 3)
- CBA found coordinated DER capacity unlocked via DCAs can reduce emissions by 18.9 MTs ($1.54b) in the most likely scenario (Chapter 3)
- Enable customer choice: On what their DER participates in, accessing some value streams without signing up to a VPP, and more value as they join a VPP. (Chapter 3 and Section 6.3.2, ARs 3, 9)
- Enable bigger systems: Customers on DCAs can install bigger rooftop PV systems.

Common DER Data Exchange Approach

- Enabling value for all: Scaled VPP uptake is underpinned by an efficient DER data exchange approach that reduces costs for participants and allows access to a greater scope of service opportunities for DER Aggregators serving customers. (Chapters 3 and 6, ARs 3, 9, 10)
- Industry cost savings: CBA found that a DER Data Hub can save participants $0.44bn in integration costs over 20 years, considering initial use cases. (Chapter 3, AR 9)
- Cheaper sharing of operational data: Sharing telemetry with DNSPs and AEMO would be cheaper than via SCADA. (Chapter 6, AR 5)

DER Participation / Visibility

- VPP capability is proven: VPPs can deliver a range of wholesale and network services and their performance improves with size and diversity (Chapter 5, ARs 6, 7)
- Separating required visibility of DER behaviour is possible without dictating VPP business models (Chapter 5, ARs 6, 7)
- Enable customer choice: On what their DER participates in, accessing some value streams without signing up to a VPP, and more value as they join a VPP. (Section 6.3.2)
- Progressive wholesale participation: Via a stepping-stone approach (e.g. visibility, self-dispatch, full dispatchability) enables VPPs to build more sophisticated capabilities as their VPPs scale. (Chapter 5, AR 5)

NSS Standardisation: 5 key factors

- Communicating NSS needs: How DNSPs publish information on NSS needs.
- Defining NSS: the characteristics that define NSS, including compliance metrics.
- Transaction terms: the contractual terms between buyers and sellers.
- Data Exchange: how data to facilitate trade is exchanged (standing and operational data).
- User experience: how participants interact. (Chapter 7, AR 10)

1. Consumer-centric approaches are needed for DER value to scale

As DER increases, customers are the key to realising the full value from DER through active coordination. Deakin University's research for Project EDGE found that:

- Achieving social licence for consumers to let aggregators utilise their DER will be critical to the successful coordination and integration of DER.
- Consumers investing in DER are motivated primarily by a desire to reduce electricity bills and be energy self-reliant, and are currently open but lukewarm about joining VPPs.
- Consumers will need incentives to join a VPP and will need to be confident that they will be better-off by participating in VPPs.
- Customers seek improved communication and transparency to better understand how their VPP works and whether it is providing them an adequate financial return.

Enabling customer choice

Continuing to enable customer choice should foster social licence and trust among customers. Choices can relate to whether customers enrol in:

- Dynamic connection agreements with DNSPs (or remain on static agreements)
- Market-active solar programs with retailers
- Coordination network tariffs (such as an SA Power Networks (SAPN) trial tariff called Diversify that rewards customers who enrol their EVs with a daily tariff rebate so that SAPN can regulate the rate of EV charging if required during a peak demand event)[22]
- A VPP to access further value by allowing the aggregator to utilise their DER to deliver other system or network support services (such as wholesale market arbitrage, Frequency Control Ancillary Services (FCAS), Reliability and Emergency Reserve Trader (RERT) contracts, Dynamic Network Pricing or local network support services (NSS)).

DEFINITION

What is social licence?*

Energy Consumers Australia defines social licence as the permission provided by consumers to government or institutions to control their DER systems, above and beyond that required by law.

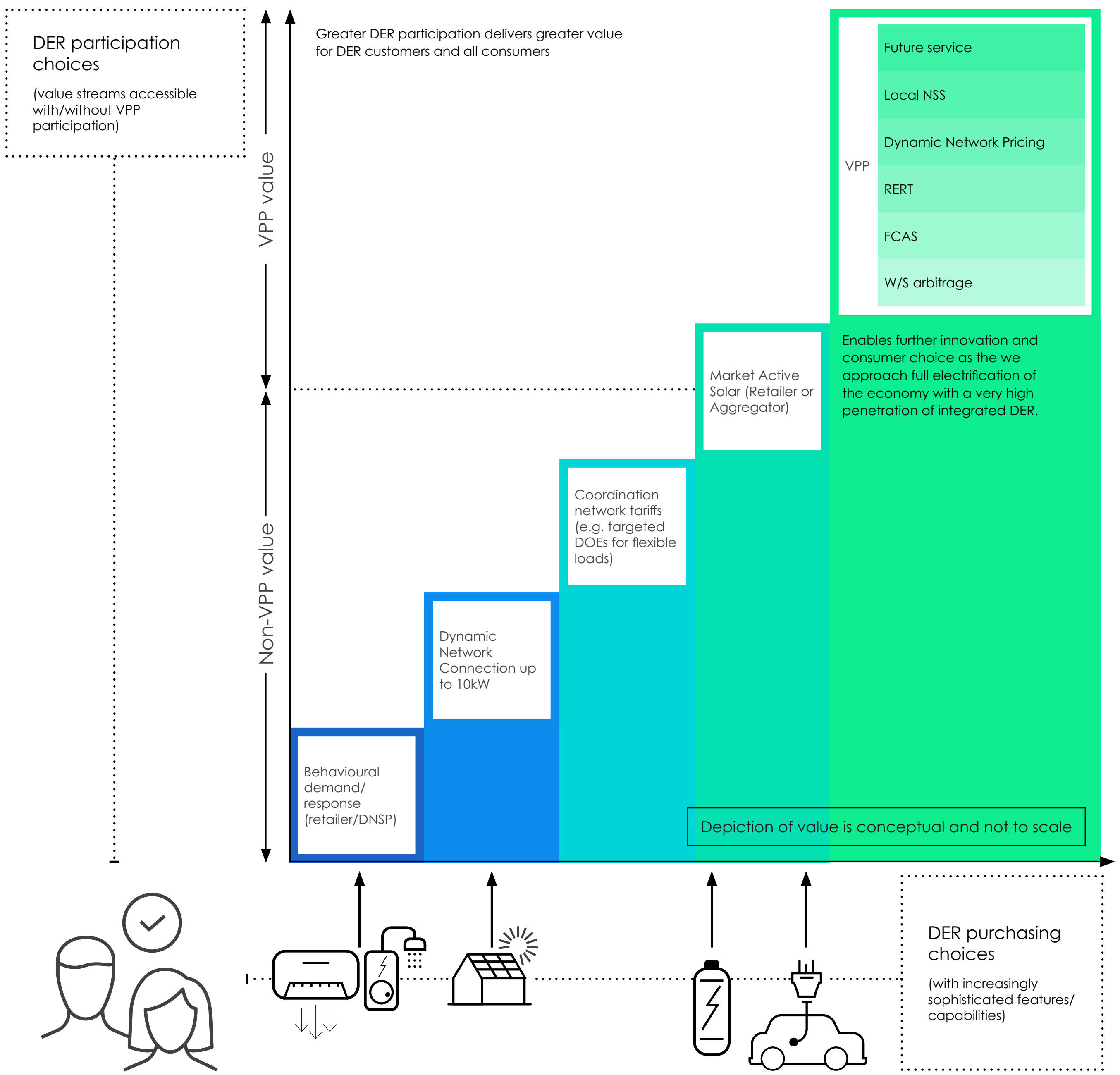
Throughout this report, the term social licence refers to the process of support and trust from customers to allow management of privately owned DER in a way that delivers benefits for the power system and all consumers.

These choices are shown in the figure below, with each DER participation choice delivering additional value to customers. Importantly, customers may be able to enrol in various programs without joining a VPP, which could help to build customer trust in the DER responding to operational signals and act as a stepping-stone to VPP participation in future. As VPP participation can enable DER to deliver more services, higher VPP participation can unlock more value for both DER customers and consumers as a whole.

22 SA Power Networks. N.d., Trial Tariffs 2023-24. https://www.sapowernetworks.com.au/public/download.jsp?id=320663

* Source: ENA. 2020. Social Licence for Control of Distribute Energy Resources: Final Report. https://energyconsumersaustralia.com.au/wp-content/uploads/Social-License-for-DER-Control.pdf

Figure 4 | Customer choices for progressive levels of DER participation



Deakin University found that accelerating VPP adoption will likely require a greater proportion of households to believe that they are benefitting more from their VPP participation than aggregators. Although the majority of customers (60%) believed that they benefitted equally with aggregators, 29% of customers believed that aggregators benefitted more than them.

These insights reinforce that VPPs need to build trust and social licence with a larger proportion of consumers to scale up VPP participation. This may be built through:

- Strong track records of operating DER and demonstrating shared value with customers so they are 'better off'
- DER cost reductions, or cost savings/increased revenues for VPPs delivering electricity services, making the financial case for VPP participation more compelling to the DER owner
- Simplifying customer models to sign up to and participate in a VPP

- Increasing storage capacity in DER (potentially via V2X capable EVs[23]) that mean more spare capacity is available for aggregator use after their customers' self-consumption needs are met.

Removing barriers on data access and DER interoperability

Interviews with aggregators outside of the Deakin University research identified how limitations on access to real-time data and DER interoperability barriers can constrain the ability of aggregators to integrate with customers' DER to deliver services.

There is a need for:

- Customers, and the service providers they nominate through explicit consent, to have access to real-time data so that they can optimise how their resources are operated. Simple access to monitoring data is also needed to calculate and assess conformance to DOEs.[24] This issue is being examined in multiple reforms[25]
- DER interoperability measures that do not just cover physical performance standards and communications protocols, but also extend to common data/information models and requirements for local control interfaces to be made available for aggregators that have explicit consent to operate their customers' DER.

Removing these barriers will enable aggregators to more easily integrate different DER into their portfolios, and enable customers to invest in DER knowing that multiple service providers can operate their DER, which increases customer choice.

2. Maintaining a secure and reliable power system in a high DER future

When planning to integrate 100GW of DER to the NEM, a first priority must be to implement the mechanisms necessary to maintain a secure and reliable power system.

Dynamic connection agreements are critical for maintaining system security and reliability

Project EDGE findings reinforce the growing industry consensus that dynamic connection agreements and dynamic operating envelopes are critical elements of a DER integration framework that will support power system security in a high DER future.

A fivefold increase in rooftop PV and electrification of the economy will increase network congestion during both peak PV export and peak demand events, so smarter ways to manage power flows on the distribution network by coordinating DER are required.

The vast majority of current DER customers in the NEM have static connection agreements that allow rooftop PV systems to export up to a set and static kW limit at any time.[26] Further increases in rooftop PV would cause PV exports to the grid to exceed the hosting capacity of the network in some areas, impacting customer service quality, causing rooftop solar to trip off and damaging costly network equipment.

Solutions to this may involve reducing static PV export limits for new connections (which will not meet DER customer expectations) or building out the network capacity to enable PV exports (which may not meet regulator or non-DER consumer expectations as it would potentially increase consumer bills).

A more efficient solution would be to offer new DER customers dynamic connection agreements. These enable consumers to install larger PV systems and export more power most of the time as long as DNSPs can send a signal (a dynamic operating envelope or DOE) to reduce exports when the local network is congested (typically a few times a year on mild, sunny spring/autumn days).

Project EDGE successfully tested the continuous operation of DOEs being sent by AusNet and acted on by several DER aggregators.

As more DER customers transition to dynamic connection agreements, the use of DOEs should reduce the use of alternative emergency backstop mechanisms to manage system security.

Compliance to DOEs and DER technical standards is vital for DER to support system security for consumers

In Project EDGE, the DNSP, AusNet Services, monitored DOE conformance using smart meter data (which is available for DNSPs in Victoria to access). The AEMC's Metering Review considered how to make it easier for DNSPs outside of Victoria to access smart meter data, which could support DNSPs in both calculating DOEs and monitoring conformance to DOEs, including compensatory control of breached DOEs.[27]

23 V2X refers to vehicle-to-everything capable electric vehicles.

24 Monitoring data refers to data that enables the measurement and verification of power flows, which enables the monitoring of how much electricity a device is consuming or exporting. This data allows AEMO and DNSPs to monitor the performance of DER against dispatch targets or DOEs, for example.

25 AEMC. 2023, Review of the regulatory framework for metering services. https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_metering_review_-_final_report.pdf; AEMC. N.d., Unlocking CER benefits through flexible trading. https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

26 AER (Australian Energy Regulator). 2022, Flexible Export Limits: Issues Paper October 2022; p 2 Box 2. https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf

27 AEMC. 2023, Review of the regulatory framework for metering services. https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_metering_review_-_final_report.pdf

Project EDGE identified that a DER data hub could enable alternative sources of data (such as telemetry from aggregators) to be shared with DNSPs. This approach could also support DOE conformance monitoring – for instance, if a DOE is applied at device level (such as to an EV charger) in future.

Compliance to DER technical standards, such as Australian Standard (AS) 4777.2:2020[28] and AS 4755.1:2017,[29] is vital to give AEMO and DNSPs confidence that DER is supporting, rather than undermining, system security – particularly in how DER responds to system disturbances.[30]

The AEMC is considering how compliance to DER technical standards should be managed, as there is significant non-compliance to AS 4777.2:2020.[31] AEMO identified that approximately 65% of new installations in quarter 1 of 2022 were non-compliant across the NEM.[32]

Through its Metering Review, the AEMC has made recommendations to support ongoing compliance, including:

- Accelerating smart meter deployment with improved data access so that DNSPs can analyse smart meter data to detect non-compliance
- Metering coordinators to provide basic power quality data to DNSPs.[33]

Project EDGE identified that a DER data hub could enable OEMs to easily share device settings data with DNSPs and AEMO, particularly if DER connects natively to the DER data hub on installation. This approach could also provide DNSPs and AEMO with visibility of changes to device settings or firmware upgrades that may impact device performance.

More cyber security measures are required for DER

EY conducted a cyber security threat assessment on the different data exchange approaches as part of Project EDGE.[34] The assessment reviewed a number of potential cyber security risks associated with DER data exchange and outlined mitigating controls that could lower the level of residual risk.

The most material risks arise due to the fact that coordinated DER will use public communication infrastructure (public internet), rather than the dedicated Supervisory Control And Data Acquisition (SCADA) networks used today by large-scale resources, which would be cost prohibitive to extend to DER.

Stakeholder engagement with aggregators during Project EDGE identified that most aggregators are focused on protecting their systems from cyber risks, but there is a gap in capabilities that 'assume compromise' and extend protection to also monitor, detect, isolate, defend and recover from cyber security risks. Stakeholder engagement also identified broad support for cyber security standards to be developed and implemented, beyond the voluntary approach to the Australian Energy Sector Cyber Security Framework.[35]

With respect to cyber security of a DER data hub itself, some stakeholders expressed a concern that a DER data hub could represent a single point of failure and increased cyber security risk. However, in practice, a DER data hub can be more efficient as it may be more cost-effective to focus resources on providing redundancies and security measures for a DER data hub as critical infrastructure than providing the same level of security across multiple DNSP and retailer systems, as would be required in a point-to-point approach to data exchange.

Consistent and visible compensatory controls are required

Compensatory controls define DER behaviour, and communications redundancy requirements, in the event of a communications failure or loss of trust in one or many market participants.

A consistent approach to compensatory controls is critical to maintaining system security in a high DER future. Consistency could be achieved through AEMO working with DNSPs so that:

28 AS 4777.2:2020 defines the conditions in which inverters should stay connected and generating power to the electricity grid, or disconnect to support power system security and prevent major events. https://store.standards.org.au/product/as-nzs-4777-2-2020-amd-1-2021

29 AS 4755.1:2017 refers to the demand response capability and modes of appliances and smart devices. https://store.standards.org.au/reader/as-nzs-4755-1-2017?preview=1

30 AEMO. N.d., DER Behaviour during disturbances. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/der-behaviour-during-disturbances

31 AEMC. N.d., CER Technical Standards Review. https://www.aemc.gov.au/market-reviews-advice/review-consumer-energy-resources-technical-standards

32 AEMO. 2023, Consumer Energy Resources Technical Standards Review (EMO0045) Submission. https://www.aemc.gov.au/market-reviews-advice/review-consumer-energy-resources-technical-standards

33 AEMC. 2023, Review of the regulatory framework for metering services, pi. https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_metering_review_-_final_report.pdf

34 EY (Ernst & Young). 2023, Project EDGE: Technology and Cyber Security Assessment. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/der-data-exchange

35 Australian Government. N.d., Australian Energy Sector Cyber Security Framework. https://www.energy.gov.au/government-priorities/energy-security/australian-energy-sector-cyber-security-framework

- The design of compensatory controls is coordinated to avoid duplicate or contradictory controls (for example, AEMO could apply some controls to VPPs while DNSPs may apply some controls through DOE implementation). The coordination of design should consider the hierarchy of interventions proportional to the magnitude of risk posed to the power system.
- All DNSPs adopt a consistent approach to DER compensatory controls, so DOEs can still be applied even when communications are lost.
- An operational procedure between DNSPs and AEMO control rooms is developed as DER penetration gains further scale to communicate the settings applied and the impact of an extended communication outage on coordinated DER operations.
- There is shared visibility of different default DER control settings that apply under different seasons or operating conditions, if appropriate.
- Appropriate testing and conformance monitoring approaches for compensatory control settings are agreed and implemented.

3. Harnessing DER for a more efficient and affordable power system

The independent EDGE CBA findings show that greater coordination of active DER in the NEM will result in an incremental benefit of up to \$5.15b under the AEMO ISP step change assumptions and up to \$6.04b under the high DER uptake assumptions.[36]

The Project EDGE arrangement of roles and market configurations was found to avoid 15.1TWh of customer rooftop solar curtailment to 2030 and up to 90.6TWh across the 20 year time horizon to 2042 under the AEMO ISP step change DER uptake assumptions and avoid 50.1TWh of customer rooftop solar curtailment to 2030 and up to 257.1TWh across the 20 year time horizon to 2042 under the high DER uptake assumptions.

The drivers of these benefits include:

- **DOE participation at scale** that enables high customer coverage, targets maximum utilisation of the distribution network and enables greater export volumes of rooftop PV to be coordinated in VPPs
- **Common infrastructure for DER data exchange,** lowering barriers to entry by reduced integration costs across industry participants and promoting greater access to DOEs and DER-based services for DER aggregators serving customers
- **DER participation / visibility,** allowing AEMO and DNSPs to improve awareness of where DER are installed on the network and how they behave, to enhance situational awareness, operational forecasting and network planning functions
- **Standardisation of local network support services,** providing a scalable and standardised arrangements for DNSPs to source local network support services through DER aggregators, deferring the need for network augmentation expenditure
- **Clear roles and responsibilities** where DER aggregators optimise DER on customers' behalf.

Each of these drivers are explored in more detail in the following sections.

Dynamic connection agreements enable the greatest savings for consumers by unlocking network capacity for VPPs to coordinate DER, and more sophisticated approaches to calculating DOEs can deliver further savings

The Project EDGE CBA found that moving from static to dynamic connection agreements can increase the amount of DER feeding into the grid and being coordinated by VPPs, displacing more expensive resources.[37]

Further, the CBA found that across the 20-year horizon total emissions avoided can be up to 18.9 t-CO2e (\$1.54b) under the AEMO ISP step change assumptions and up to 32.8 t-CO2e (\$2.60b) under the high DER uptake assumptions.[38]

Project EDGE also tested different approaches to calculating DOEs. Simple approaches to DOE calculation can be relatively easy to implement using limited data but are theoretically conservative, meaning they apply a buffer of network capacity to account for uncertainty, which means that DER may be constrained more than needed.

More sophisticated approaches to calculating DOEs – for instance, moving from a simpler approximation methodology to a low voltage network model approach – reduces uncertainty and the buffer applied to DOE so that DER is able to utilise more network capacity. This releases the 'spare capacity' reserved by the network as headroom for consumers to use.

36 Deloitte Access Economics. 2023, Project EDGE CBA Final Report, p 44. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

37 Deloitte Access Economics. 2023, Project EDGE CBA Final Report, p 44. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

38 Deloitte Access Economics. 2023, Project EDGE CBA Final Report, Executive Summary, p.11. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

39 Project EDGE. 2023, Project EDGE: Testing different DOE approaches at DER penetration levels in real-world networks. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge--testing-different-doe-approaches-at-der-penetration-levels-in-realworld-networks--work.pdf?la=en

UoM's techno-economic modelling confirmed that more sophisticated DOE design can release more DER hosting capacity on the network, improving both network utilisation and DER capacity to deliver electricity services.[39] However, graduation to a LV network model approach may not be suitable for all DNSPs depending on the data inputs available to them (e.g. network data visibility).

The CBA suggests an accelerated DOE rollout can deliver consumer benefits sooner, particularly if DER uptake continues at the forecast rate. As DOEs are a relatively new concept and would be a significant shift in the way customers are able to use their DER, a progressive approach to DOE implementation should be considered.

Project EDGE has developed an indicative accelerated DOE road map for consideration by industry. The road map commences with the transition to flexible export limits, introduces simple forecasting models and applies a 'maximise service' objective function. As constraints become more frequent, the road map moves to more frequent and more sophisticated DOEs and more complex forecasting, and then potentially moves to flexible import limits and more innovative approaches, such as shaped operating envelopes, if proven successful in ongoing trials.

This progressive approach would enable the value of DOEs to be realised quickly and allow DNSPs to invest incrementally in network monitoring and more sophisticated model-based DOEs over time, guided by local DER penetration levels.

Investment in DOE calculation models may be overseen by the AER to ensure it is prudent and efficient and in line with a network's DER penetration levels. There could be a case for periodic analysis after the fact (as part of regulatory oversight) of operational DOEs against actual network limits to make sure DER is not overly constrained beyond what is deemed appropriate.

A DER data hub approach to exchanging operational information (such as DOEs) across the NEM can deliver \$0.44b in savings and unlock further value from innovation for all consumers when compared to the current point-to-point approach

A high DER future requires sensitive data to be shared securely among many organisations and systems to facilitate DER coordination. Project EDGE tested how to best harness digital technologies to enable secure, efficient and scalable ways to exchange vast volumes of data among industry participants to coordinate DER.

Using DOEs as a tool to manage power flows on the distribution network has been proven effective in Project EDGE and other trials (such as Project Evolve[40]), and is starting to be rolled out for new PV connections across the NEM.[41]

DNSPs will need to scale up systems to calculate and communicate DOEs over the coming years, with each DNSP currently requiring DER and aggregators to connect to their systems in a point-to-point approach.

DNSPs are collaborating to each adopt the Common Smart Inverter Profile for Australia (CSIP-AUS)[42] as a standardised communications profile, but under the current expected projection of implementation, aggregators will incur additional costs to connect to each DNSP's separate systems to receive DOEs.

Project EDGE has tested a DER data hub as a more efficient way for DOEs and other relevant DER data to be exchanged amongst industry participants, using the same schema as CSIP-AUS.

The CBA found that across a 20-year horizon a DER data hub can reduce costs by \$0.44b when compared to a point-to-point approach, and should deliver further upside through improving access to additional DER use cases that can support greater operational coordination of DER across the industry.

40 ARENA (Australian Renewable Energy Agency). 2023, evolve DER Project. https://arena.gov.au/projects/evolve-der-project/

41 For instance, in South Australia under dynamic exports requirements for the Smarter Homes program from 1 July 2023.

SA Power Networks. 2022, Important changes to SA Dynamic Export Regulation affecting inverter sale and installation. https://www.sapowernetworks.com.au/data/314111/important-changes-to-sa-dynamic-export-regulation-affecting-inverter-sales-and-installation/

Also in South Australia, the ARENA-funded Flexible Exports Trial has allowed South Australia Power Networks (SAPN) to offer a flexible exports option for new and upgrading rooftop PV customers in constrained areas since 23 September 2021. The aim of the trial is to make the flexible exports option a standard service offering after the trial ends.

SA Power Networks. N.d., The Flexible Exports Trial. https://www.sapowernetworks.com.au/industry/flexible-exports/flexible-exports-trial/

In Victoria, new rooftop PV installations installed under the Solar Homes and Solar for Business Programs will need to be dynamic export capable by 1 March 2024 to allow for the future implementation of dynamic export arrangements by DNSPs.

Solar Victoria. 2023, New Notice to Market to support growing demand for Solar. https://www.solar.vic.gov.au/new-notice-market-support-growing-demand-solar

The Queensland Government is also working closely with Energy Queensland and Powerlink to plan a staged rollout of dynamic connections and dynamic operating envelopes.

Queensland Government. 2023, Emergency backstop mechanism. https://www.epw.qld.gov.au/about/initiatives/emergency-backstop-mechanism

42 ARENA. N.d., Common Smart Inverter Profile Australia. https://arena.gov.au/knowledge-bank/common-smart-inverter-profile-australia/

The Standards Australia handbook of CSIP-AUS (more formally known as SA HB 218:2023) has been published, and is available for free on the Standards Australia store website. Standards Australia. 2023, SA HB 218:2023: Common Smart Inverter Profile – Australia with Test Procedures. https://store.standards.org.au/product/sa-hb-218-2023

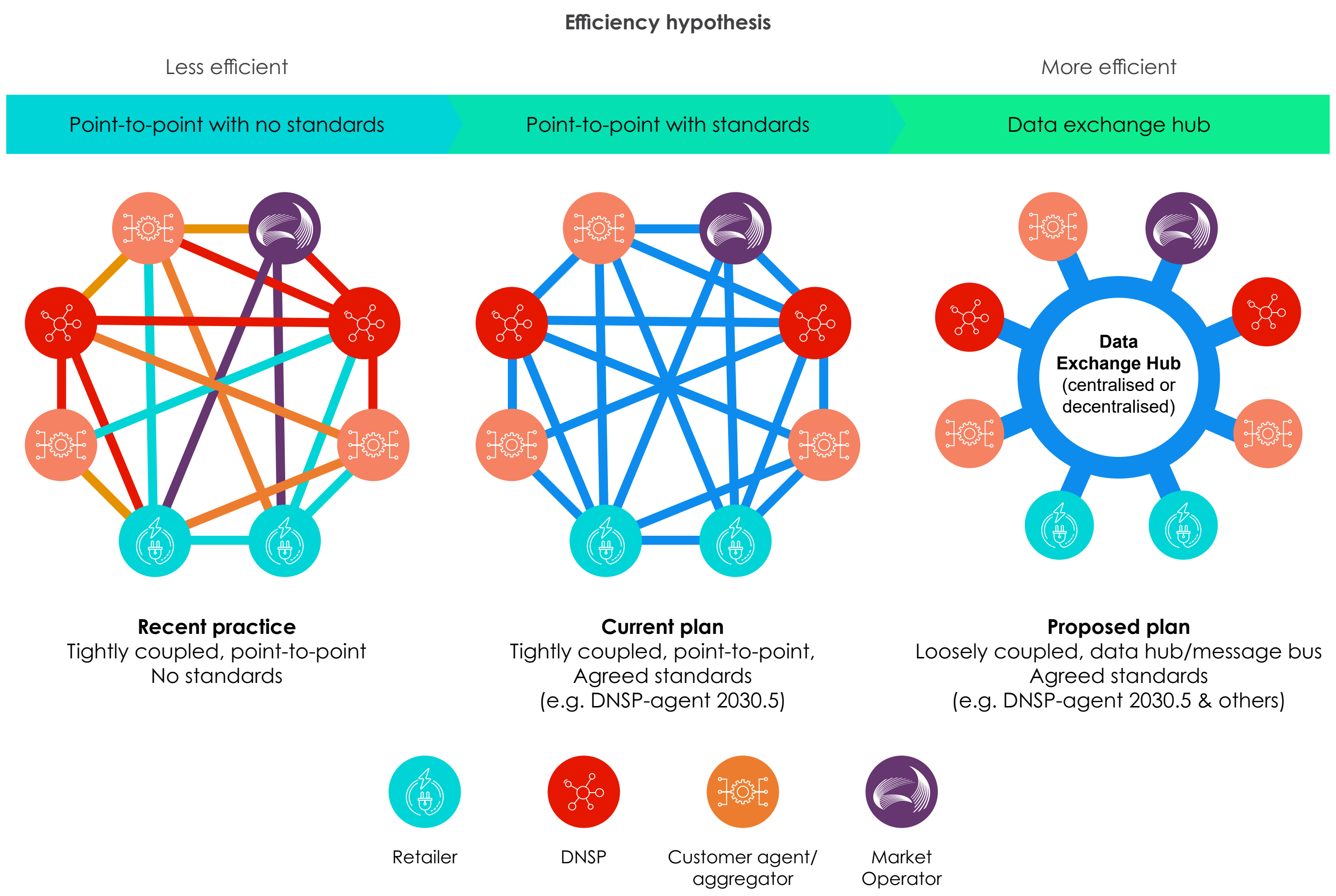
Other relevant DER data exchange use cases include retailers also seeking to send dynamic export limits to customer owned DER to manage their exposure to more frequent negative price periods. To do this, they could either set up their own systems to send export limits to customers' PV or they could use DNSP systems, which may create regulatory issues. This is being tested in the SA Power Networks Market Active Solar Trial in collaboration with Simply Energy and AGL.[43]

For the non-hub models to scale up, each retailer would need to connect to each DNSP's systems to send dynamic export signals to their customers' DER.

Ryan Wavish, GM of Simply Energy Solutions (which is participating in the Market Active Solar Trial), sees potential value in an industry DER data hub:

"One of the big challenges in accessing and monetising DER flexibility is the complexity and cost of interconnectivity. The more it costs, the less there is to share with customers. A DER data hub could significantly reduce this cost and complexity, particularly in light of the industry's progression towards dynamic export limits."

Figure 5 | DER data exchange efficiency hypothesis



The Project EDGE hypothesis is that establishing a NEM DER data hub would enable participants to send and receive signals with any other party connected to the DER data hub (including AEMO, aggregators, DNSPs or retailers) which would save time and resources for each party.

Project EDGE has proven, at small scale, that the DER data hub works in practice through field testing. The advantages of a hub approach over a point-to-point approach are supported by the following:

- The Deloitte Access Economics CBA outlined above. This analysis also identified further benefits that were not included in the scope of the quantitative analysis[44]

43 ARENA. 2023, Pioneering rooftop solar trial to prove benefits for customers, retailers and networks from energy transition. https://arena.gov.au/news/pioneering-rooftop-solar-trial-to-prove-benefits-for-customers-retailers-and-networks-from-energy-transition/

44 Deloitte Access Economics. 2023, Project EDGE CBA Final Report, p 47. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

- A theoretical Technology and Cyber assessment by EY on approaches to DER data exchange identified that a point-to-point model scored lowest in a Multi Criteria Analysis when compared to DER data hub approaches and is not suitable in a high DER future.[45]

Point-to-point integrations may be manageable for individual uses cases at small scale, such as a small number of aggregators integrating with one DNSP to obtain DOEs. However, the scale of DER anticipated in the ISP's most likely scenario, requires more efficient and scalable ways to integrate DER into electricity markets and the power system.

Project EDGE also tested two technology models for a DER data hub:

- Centralised model in which the market operator maintains the DER data hub and acts as a central data broker receiving / transmitting data in a 'hub and spoke' model, like the current business to business (B2B) e-Hub[46]
- Decentralised model in which there is no central broker and technology components enable codified partitioning of data to the right participants using digital identities. This approach could also enable alternative ownership, governance, operating and cost recovery models to the traditional centralised model.

EY's assessment explored the theoretical advantages and disadvantages of each approach to implementing a DER data hub.

While the CBA, practical and theoretical assessments in Project EDGE support the case for implementing a DER data hub rather than scaling up point-to-point approaches, detailed design and technology choices for an enduring DER data hub should not be made until key questions on design principles, policy objectives and potential use cases are agreed among industry participants.

These key questions relate to, but are not limited to, the following topics:

- **Ownership and cost recovery:** Who should own a DER data hub and how should costs be recovered? Should AEMO own the data hub and recover costs through market fees or should ownership be shared amongst key industry participants with costs recovered through tariffs?
- **Governance:** Who should be responsible for operating a DER data hub and developing associated B2B procedures? AEMO is responsible for the current B2B e-Hub. The Information Exchange Committee, which is made up of industry stakeholders and chaired by AEMO, is responsible for the development of the B2B procedures. Is this an appropriate governance model or should alternative governance models be considered?
- **Operation, innovation and development:** Are there approaches to operating a DER data hub and implementing development updates that would foster an ecosystem of innovation around the common digital infrastructure? AEMO is currently responsible for operating the B2B e-Hub and implementing development updates to it.[47] An alternative approach may be to broaden the number of parties with permission to develop applications for a DER data hub.

For example, DNSPs may want to develop applications connected to the DER data hub for digital solutions to procure local network 'flexibility' services at scale from DER aggregators. This could enable DNSPs to operate their own local flexibility markets while supporting standardised DER data exchange. This is discussed further in the next section.

- **Connectivity and use cases:** Project EDGE tested communications between AEMO, AusNet (as DNSP) and several aggregators through a DER data hub. A design choice to consider is whether connectivity should be extended to enable DER to connect natively to the DER data hub as well as industry participants. During stakeholder engagement activities one aggregator stated:

"One of the immediate use cases for a DER data hub could be to facilitate simple, cost-effective access to solar inverters in order for both DNSPs and aggregators to manage solar exports for both network and wholesale market value, enabling customers to be reimbursed for the financial impacts of solar curtailment."

Facilitating DER to natively connect to a DER data hub – for instance, through a plug and play user experience on installation – would enable customers to switch more easily between aggregators that are connected to the DER data hub or to receive flexible export limits from DNSPs and retailers even if they do not want to be part of a VPP (enabling consumer choice).

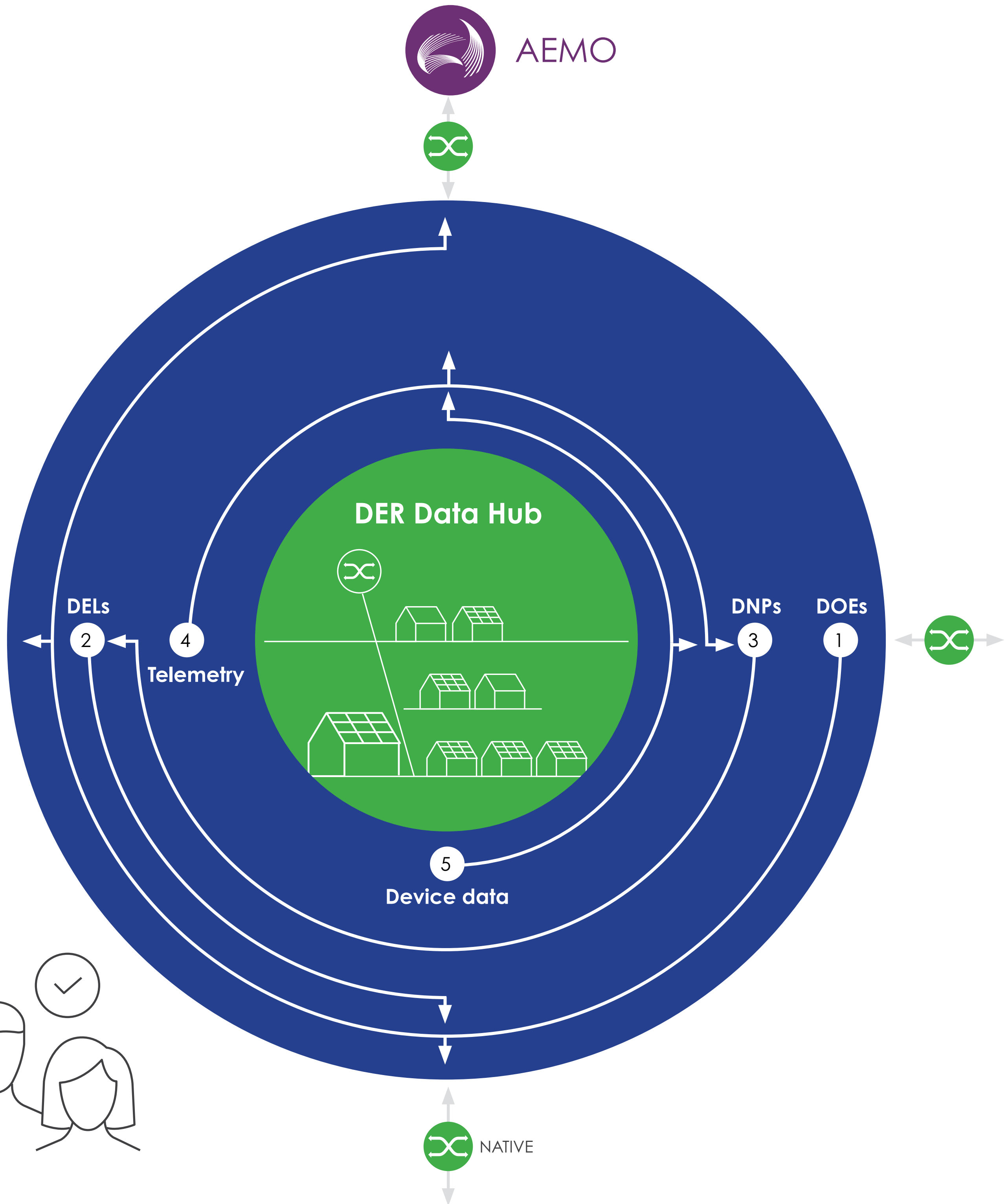
A conceptual view of a potential first iteration of a DER data hub beyond Project EDGE is shown in the figure below.

45 EY (Ernst & Young). 2023, Project EDGE: Technology and Cyber Security Assessment. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/der-data-exchange

46 AEMO. 2018, Shared Market Protocol Technical Guide: Provides participants with the technical specifications for the delivery of B2B transactions using the e-hub. https://aemo.com.au/-/media/files/electricity/nem/retail_and_metering/b2b/2018/b2b-smp-technical-guide.pdf?la=en&hash=E99BF018F014EC32B792A7D1D55C0D23

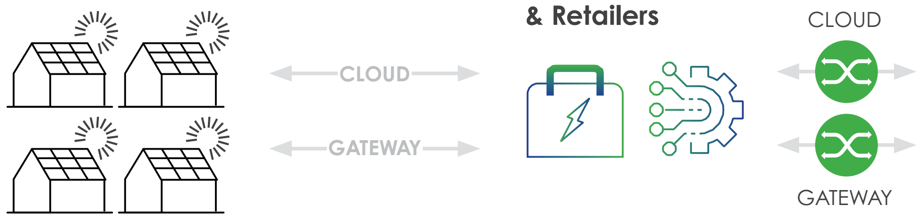
47 NER, clause 7.17. https://energy-rules.aemc.gov.au/ner/347/38587

Figure 6 | Conceptual view of a potential DER data hub beyond Project EDGE



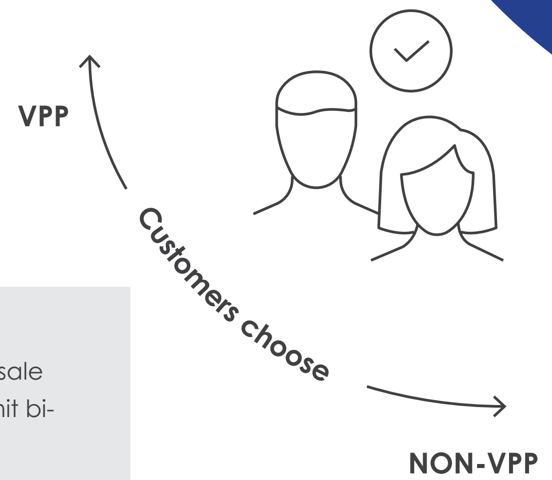
VPP customers

Aggregators & Retailers



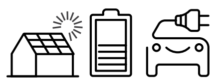
If customers sign up to a VPP, the aggregator) can connect with customers' DER and to the DER Data Hub through a gateway device or through the cloud.

Retailers can also send signals (e.g. dynamic export limits) to customers whose DER is natively connected to the DER Data Hub



Key points to note

- **Wholesale services:** Beyond Project EDGE it is envisaged that VPPs participating in the wholesale market would use existing NEM systems to submit bi-directional offers and receive dispatch targets.
- **Local Network Support Services (NSS):** It is not envisaged that there is an immediate need for digital solutions to procure local NSS at scale. Immediate actions could be focused on how to how to standardise NSS trade.

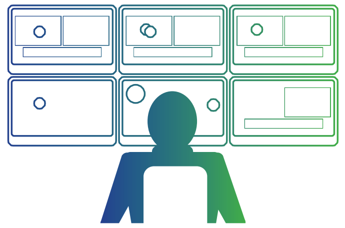


Non-VPP customers' DER

Customers connect their DER to the DER Data Hub natively on installation, and choose whether to join a VPP or not.

Natively connecting to the DER Data Hub will enable their DER to receive DOEs from DNSPs or dynamic export limits from retailers without joining a VPP.

Distribution system operator



DSOs use the DER Data Hub to:

- Send DOEs, or dynamic tariff/price signals
- View updates to standing data/inverter settings to monitor standards compliance
- Send dispatch signals and receive telemetry relating to contracted network support services

#	Use case description
1	**DOEs** = Dynamic Operating Envelopes. This includes Co-Ordination Tariffs signals that may send targeted DOEs (e.g. to coordinate flexible loads). Sent from DSOs to DER devices, Aggregators and AEMO (for visibility)
2	**DELs** = Dynamic Export Limits. Sent from Retailers to DER devices
3	**DNPs** = Dynamic Network Prices. Sent from DSOs to Aggregators.
4	**Telemetry** = performance measurement data for VPP portfolios. Sent from Aggregators to AEMO and DSOs.
5	**Device data** = standing data submitted on installation plus updates to settings and firmware over time.

Design choices, subsequent detailed design activities and consideration of an implementation roadmap could all be progressed within the broader context of the Industry Data Exchange and DER Data Hub and Registry Services projects in the NEM2025 Program,[48] and through engagement with industry stakeholders.

A spectrum of technology options are available to enable the chosen design for a DER data hub, but design choices should be made before technology solutions are procured.

As VPPs scale, a stepping-stone approach to wholesale market participation can strike a balance between the VPPs' costs of participation and visibility/dispatchability benefits to support power system security (keeping the lights on)

As the power system and market operator for the NEM, AEMO is responsible for maintaining power system security and reliability throughout the energy transition. Maintaining power system requirements[49] of predictability and dispatchability are prerequisites to support this function.

VPPs are already responsive to extremely high or low/negative wholesale prices without participating directly in the market.

As VPPs scale to higher capacity portfolios, visibility and coordination of DER will be essential to mitigate the additional costs of managing the supply demand balance without visibility of large, aggregated, price-responsive resources.

The current NEM framework does not support or reward visibility or scheduling of DER in the market, which reduces operational oversight and market efficiency.[50] While the integration of DER into scheduling and dispatch processes will require an enhancement of aggregators' capabilities, it is also likely to enable DER to access current and emerging markets and services, providing new opportunities to contribute to (and be rewarded for) the secure and reliable operation of the power system.

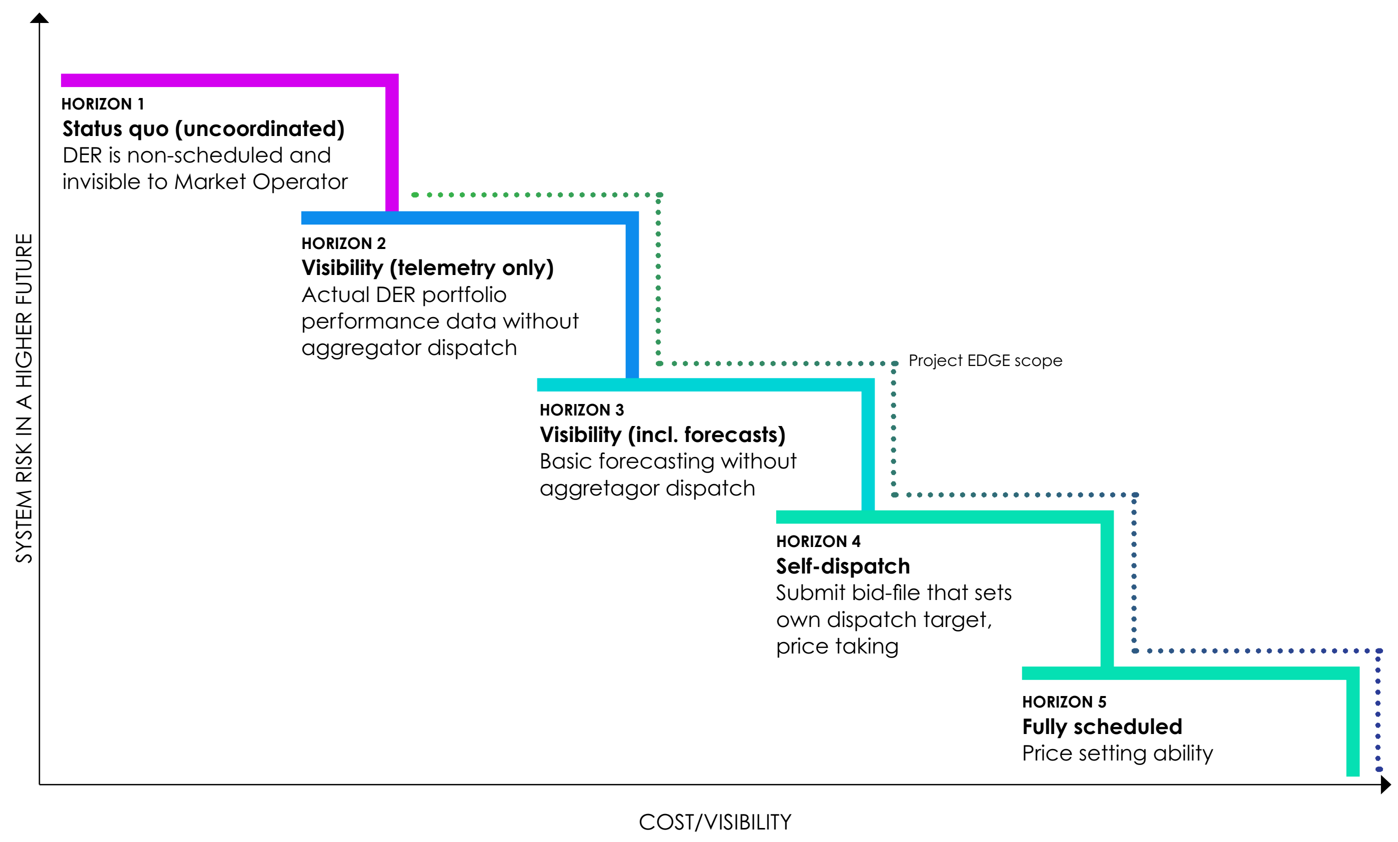
Project EDGE tested progressive levels of participation in the wholesale market, as shown below.

DEFINITION

Aggregator to retailer services

Price-responsive VPPs provide a benefit to retailers – discharging a battery during a high price event reduces the retailer's exposure to high wholesale prices and charging during a low negative price event reduces the retailer's exposure to paying negative prices for customer solar export. This pathway via retailers is currently the only access mass market DER has to benefit from wholesale energy market exposure. This approach means aggregators are required to negotiate and form agreements with retailers that have a stronger negotiation position. Retailers have the direct customer relationship and represent the customer in the wholesale market as the financially responsible market participant (FRMP) for the customer's premises and taking on the market price exposure risk.

Figure 7 | Stepping-stone approach to wholesale market participation



Participating aggregators provided feedback that each step in the horizons above carries additional costs that reduce available value to share with customers. While aggregators recognise the need for visibility and coordination as they scale, it is important to strike the right balance so that costly obligations are not imposed on aggregators before they have sufficient scale to reasonably absorb the costs of moving to the next step in participation.

Aggregators may be better placed to absorb these costs if they could access and participate in other value streams, such as FCAS, the Wholesale Demand Response Mechanism (WDRM)[51] (in future), RERT or local NSS.

In Project EDGE, aggregators demonstrated capability to deliver a variety of services and respond to complex market events (although inconsistently) after only a short development window. Capabilities can be built on over time and aggregators could benefit from a progressive (simple to complex), service-based stepping–stone approach, aligning revenue opportunities with system development to fund portfolio growth. Aggregators could also use B2B services (such as local NSS) to develop capability before making steps towards market participation.[52]

48 The NEM2025 Program was formed by AEMO to manage the implementation of the Energy Security Board's post-2025 electricity market design reform package through cross industry collaboration and engagement.

AEMO. N.d., About the NEM Reform Program. https://aemo.com.au/initiatives/major-programs/nem2025-program/about-nem2025-program

49 AEMO. 2020, Power System Requirements July 2020 Reference paper. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf?la=en

50 The AEMC is currently considering rule change proposals from AEMO on Integrating Price-Responsive Resources into the NEM.

AEMC. N.d., Integrating price-responsive resources into the NEM. https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem; Unlocking CER benefits through flexible trading. https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

51 AEMO is currently working with industry to implement a WDRM in the NEM. It would work by allowing demand side (or consumer) participation in the wholesale electricity market at any time. However, it would most likely occur at times of high electricity prices and electricity supply scarcity. Demand Response Service Providers (DRSP) would classify and aggregate the demand response capability of large market loads for dispatch using the existing bidding and scheduling processes. The DRSP would receive payment for the dispatch, measured against a baseline estimate, at the electricity spot price.

AEMO. N.d., Wholesale demand response mechanism. https://aemo.com.au/en/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism

52 B2B services in this context refers to services that could be transacted between an aggregator and another industry actor, including DNSPs and retailers.

Field testing identified the primary capabilities that aggregators need to develop for wholesale market participation:

- **Conformance to DOEs sent from DNSPs.** Field tests demonstrated aggregators generally conformed to DOEs, both at the portfolio level (Dispatchable Unit Identifier (DUID)) and individual connection point level (National Meter Identifier (NMI) level), but results showed approximately 14% of non-conformance during constrained periods.
- **Provision of visibility through sharing telemetry data at operational timescales.** Across aggregators, the overall completeness of telemetry ranged from 90-95% when transmitted at a 1-minute frequency. Certain system architectures showed a completeness of 98-100% and that providing portfolio telemetry with this level of completeness at less than a 1-minute frequency (down to 5 seconds) was technically feasible. Associated costs would need to be recoverable from market activities to make this frequency commercially viable, the magnitude of which will vary with aggregator system design choices. Providing visibility by sharing VPP telemetry through an internet-based data hub is also more cost-effective than applying the Power System Data Communication Standard[53] to VPPs.[54]
- **Reliable forecasting capabilities to provide longer-range forecasts of available capacity for market price formation.** Forecasts of participating DER generation and consumption at various price points over various operational horizons will also be critical to provide visibility for AEMO to maintain accuracy and improve its operational load forecasting, which is fundamental for efficient market scheduling and managing system security.

  Field test data was used to analyse forecasting error across different time horizons leading up to dispatch (from 48 hours ahead to 5 minutes ahead – the final bi-directional offer) for each aggregator portfolio. The forecasting 5 minutes ahead of the dispatch interval had the highest accuracy (lowest error).

  Field test analysis results showed there were times throughout the Project EDGE trial where the three active aggregators were not actively adjusting their bids and offers as part of market price formation. There was a trend of aggregators applying a 'set and forget' strategy for bidding.

  The practice of bids and offers not reflecting actual available capacity at different price points, or deliberate late re-bidding, can decrease market confidence in forward information about the market, including AEMO's pre-dispatch forecasts. Additionally, price formation in the market requires more accurate forecasts over a longer time horizon than 5 minutes to 1 hour. Therefore, 'set and forget' bidding, and late rebids by VPPs might lead to inefficient outcomes.
- **Conformance to dispatch targets, including linearly ramping from one dispatch target to another.** Performance in the field tests identified that participating VPPs showed promising capability to deliver step change responses to price events; however, they were not observed to consistently meet standards for scheduled resources regarding dispatch conformance (including linear ramping).

  Some aggregators developed capability to ramp linearly part of the time. Those that could simultaneously coordinate both load and generation (technically and with appropriate customer permissions) performed better, and all aggregators performed more accurately when allowing headroom in their bids. At times, aggregators withheld controllable capacity from the market to act as headroom buffer for uncertainties in their portfolios.
- **An understanding of market risk dynamics and performance requirements for dispatchable resources.** Field tests demonstrated aggregators did not always follow project requirements (e.g., did not follow dispatch instructions in some isolated cases) that were intended to test and mirror market requirements.
- **Ability to deliver wholesale and local services simultaneously.** Field tests showed that aggregators can deliver local NSS while adjusting wholesale market bids to manage conformance to dispatch targets. On the infrequent occasions when a local NSS may conflict with a wholesale price signal (e.g., a voltage reduction service coincident with a high wholesale price), the aggregators indicated they would be able to prioritise delivery of the local network service and adjust the remainder of its wholesale portfolio to meet the dispatch target.
- **Visibility of compensatory controls settings.** Connection agreements can require compensatory control settings to revert DER to minimal export on the loss of communications or another trigger. There would also be a need for compensatory controls with regard to directing DER to follow the last dispatch instruction. The number of intervals to which this control would apply requires further consideration by AEMO and industry as batteries would eventually run out of charge.

Another compensatory control would be the ability for aggregators to continue forecasting their DER fleet if there were partial communications outages. This also highlights the need for reliable longer-range forecasts. Consistent application and visibility of compensatory control settings is important for DNSPs and AEMO to understand the potential implications of widespread communications outages. Testing for conformance to compensatory controls settings may also be a pre-qualification requirement for VPPs (to deliver different services) or become part of ongoing conformance testing.

A foundational element for a dispatchability model is for AEMO's registration and portfolio management processes to be enhanced so that registered portfolios can be updated (potentially daily) as DER join or switch between VPPs. It may be possible to incorporate this into updates made to other initiatives in the NEM2025 Program.

Standardising local network services procurement can reduce transaction costs and lead to more scalable trade of local services

The need for DNSPs to procure local network support (or 'flexibility') services at scale in Australia is not immediate, unlike in the UK where distribution networks tendered for almost 4GW of flexibility services in 2022 to manage peak demand congestion and defer network augmentation.[55]

In the Australian context, the primary cause of distribution network congestion is related to voltage congestion from peak PV exports, which is being managed through static export limits, dynamic connections and flexible export limits.

As the Australian population grows and the economy electrifies towards net zero targets, it is anticipated that peak demand congestion will grow, leading to increased localised congestion on distribution networks.

The ongoing transition towards cost-reflective tariffs,[56] including two-way tariffs, and new approaches such as dynamic network pricing (as is being tested in Project Edith[57]) or coordination tariffs (such as SAPN's Diversify trial tariff[58] which applies targeted DOEs to flexible loads on an opt-in basis) could help DNSPs manage network congestion. However, the example in the text box below outlines why an emergency backstop for flexible loads (potentially using flexible import limits) will be needed in future.

53 AEMO. 2023, Power System Data Communication Standard: National Electricity Market. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/AEMO-Standard-for-Power-System-Data-Communications.pdf

54 A report commissioned by the AEMC estimated that the costs of connecting to SCADA at a basic level would be $0.7-1m, and $2-2.5m for more advanced connections associated with scheduling.

GHD Advisory. 2021, Assessment of scheduling costs: Final Report - Australian Energy Market Commission 07 June 2021. Available: https://www.aemc.gov.au/sites/default/files/documents/ghd_report_-_assessment_of_scheduling_costs_-_final.pdf

55 Energy Networks Association (UK). N.d., Flexibility Services. https://www.energynetworks.org/creating-tomorrows-networks/open-networks/flexibility-services

56 AER. N.d., Network tariff reform. https://www.aer.gov.au/networks-pipelines/network-tariff-reform

57 Ausgrid. N.d., Project Edith. https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith

58 SA Power Networks. N.d., Trial Tariffs 2023-24. https://www.sapowernetworks.com.au/public/download.jsp?id=320663#:~:text=The%20trial%20tariff%20Electrify%20provides,%3A00am%20%E2%80%93%204%3A00pm.

DEFINITION

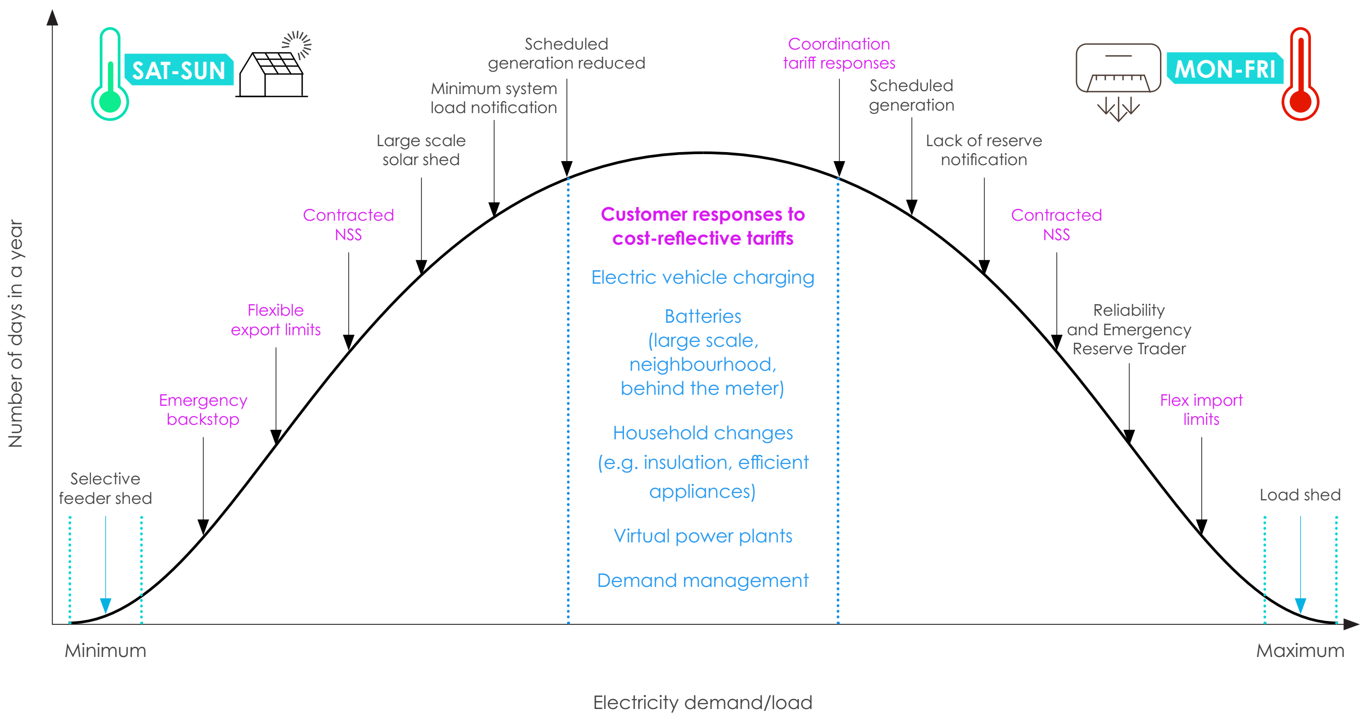
Emergency flexible import limits

Consider a future scenario where residential and commercial energy use is largely electrified. On day 2-3 of a summer heatwave that is already pushing peak demand records, a forecast evening thunderstorm may cause consumers to simultaneously use major appliances for cooking, cooling and charging up their cars/stationary batteries ahead of the storm rolling through, causing a 'super-peak' in electricity demand.

In this scenario, AEMO and DNSPs may need to enact emergency flexible import limits to maintain system and local network security, as it may be inefficient to build out network infrastructure to cater for this infrequent scenario, and curtailing flexible loads in an emergency may be preferable to indiscriminate load shedding

The figure below outlines the range of available measures for managing minimum demand (from peak PV exports) and maximum demand events.

Figure 8 | Range of available measures for managing minimum demand from peak PV exports, and maximum demand event[59]



59 Adapted from a Victorian Government figure in the consultation paper for Victoria's emergency backstop mechanism for rooftop solar. Victorian Government. 2023, Victoria's Emergency Backstop Mechanism: Consultation paper, p 10. https://engage.vic.gov.au/victorias-emergency-backstop-mechanism-for-rooftop-solar

Between customer responses to cost reflective tariffs and the need to implement emergency measures, it is likely that contracted network support services (NSS) may be used by networks where greater certainty from a contractual response is needed to manage congestion and defer/displace the need to augment networks to address peak demand constraints.

While the timing of when each DNSP may need to procure NSS at scale may vary, it is reasonable to suggest that NSS will play an increasing role as the economy electrifies. This is also on the ESB's DER Implementation Plan, Horizon Two.[60]

However, the way NSS are currently traded is based on bespoke, bilateral negotiations that are costly processes and not scalable. Standardisation of NSS would reduce the costs to DNSPs for procuring NSS from DER and would enable aggregators operating across the NEM to transact for a similar NSS, in similar way with any DNSP across the NEM.

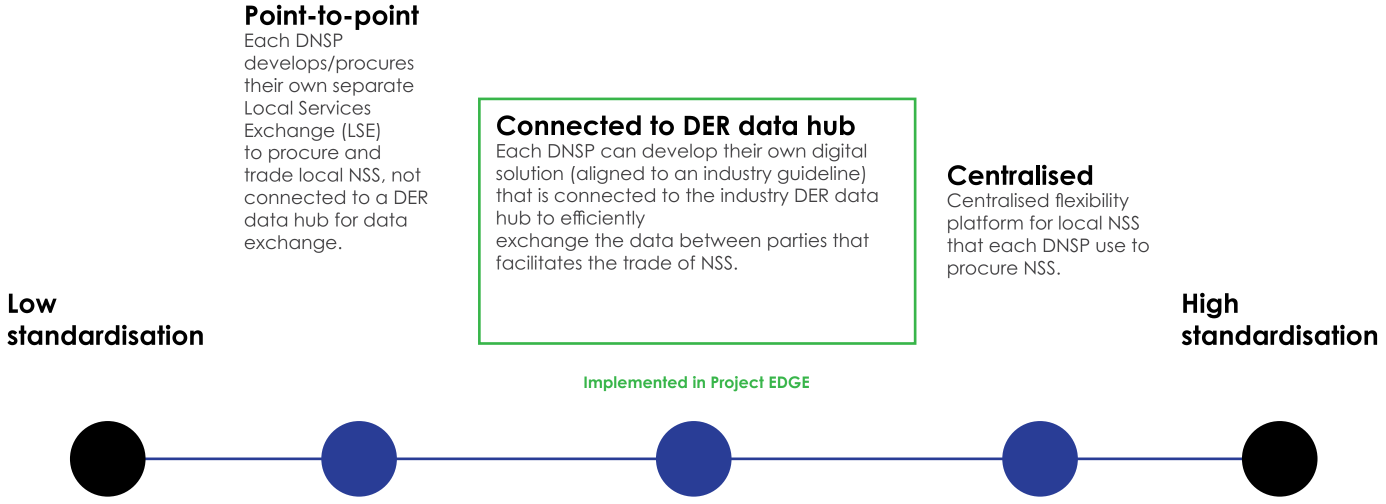
Standardisation of local network services can be broadly broken into five main factors:

- **Communicating needs –** how DNSPs communicate current or forecasted requirements to procure NSS, potentially using digital mapping solutions to relay locational service attributes
- **Service definitions –** the characteristics that define the service being procured. The services definitions tested in Project EDGE are in section 7.3.2
- **Transaction terms –** the contractual terms for NSS trade financial settlement. Project EDGE did not test transaction terms as no money was exchanged for the delivery of NSS in the trial
- **Data exchange –** how different types of data such as standing data, portfolio data, arming instruction/dispatch triggers and operational telemetry to verify performance are exchanged. Data for NSS tested in Project EDGE was successfully exchanged through a DER data hub.
- **User experience –** how different participants (e.g., buyers and sellers) interact, through user interfaces, with digital solutions to facilitate the trade of NSS.

How local network services are traded in future will depend on the extent to which these factors are standardised. Different approaches to standardisation can be considered on a spectrum, as shown below.

60 ESB (Energy Security Board). N.d., DER Implementation Plan – reform activities over three-year horizon, p 1: Further definition of DSO responsibilities re community storage tariffs, load control and procurement and delivery of DER network services. https://www.datocms-assets.com/32572/1639638279-attachment-a-der-implementation-plan-three-year-horizon-december-2021.pdf

Figure 9 | Spectrum of approaches to standardisation of local network support services (NSS)



Standardisation	Low standardisation Point-to-point	Medium standardisation connected to DER data hub	High standardisation centralised
Service definition	Defined by each DNSP differently	Standardised services characteristics defined in an industry guideline that DNSPs co-design and implement	Services are defined (in collaboration with DNSPs and aggregators) with firm specifications in the single centralised flexibility platform
Transaction terms	Defined by each DNSP differently	Standardised contractual terms defined by an industry guideline that DNSPs co-design and implement. Settlement occurs bilaterally outside of DER data hub (i.e. no clearing house)	Terms are standardised and baked into participation on the flexibility platform. Settlement can occur through the platform as a clearing house
Data exchange	Aggregators exchange data directly with each DNSP separately	Multiple LSEs can be connected to the industry DER data hub so that aggregators and DNSPs can efficiently exchange data to facilitate the trade of services	Single LSE is embedded as part of the DER data hub, enabling standardised data exchange
LSE operation	DNSP operated	DNSP or independently operated	Operated by independent party

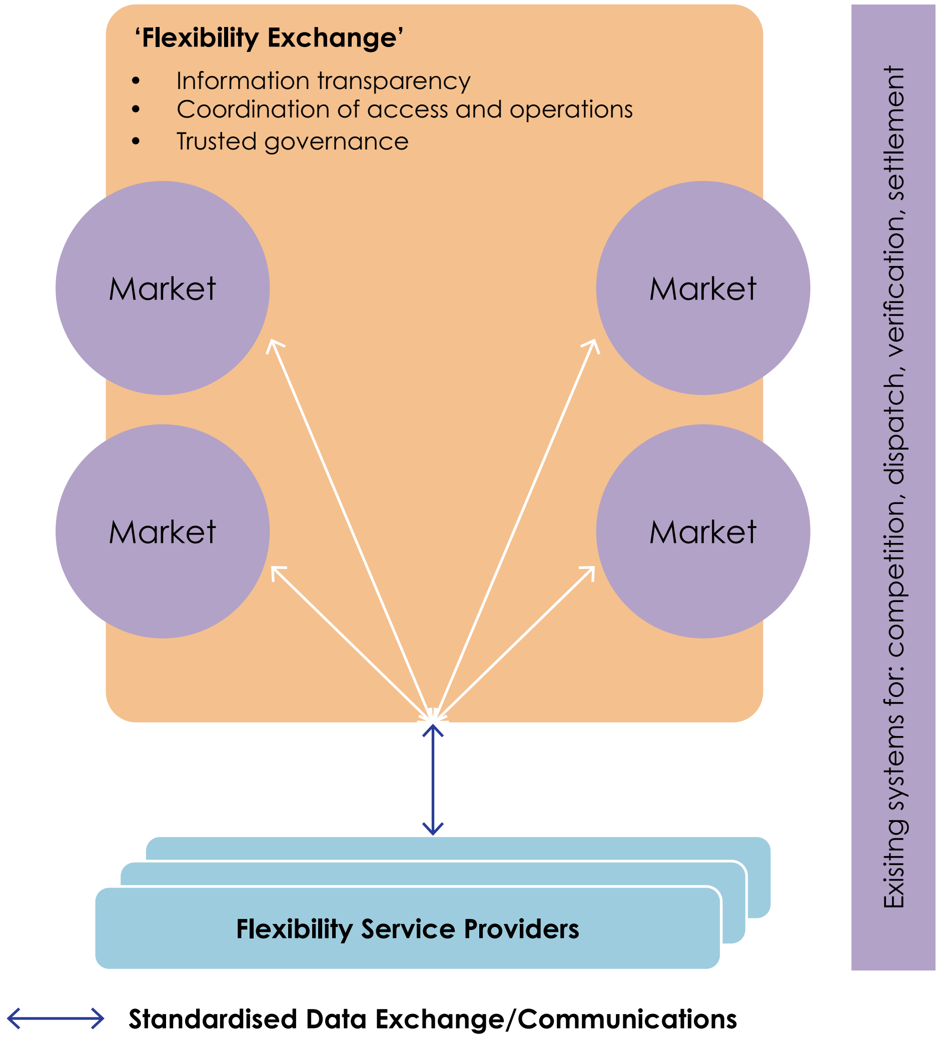
From an aggregator perspective, the centralised option should provide the most standardised user experience when delivering local network services for different DNSPs. However, from a DNSP perspective, the centralised option may restrict their ability to design and trade services that meet their specific needs.

Project EDGE successfully tested the medium option in the figure above in which AusNet designed the services to test in a Local Service Exchange (LSE) and exchanged arming signals, service event triggers and operational data through the data hub, although services were not actually 'settled' in the field testing. Aggregators successfully included NSS commitments in their wholesale market bids to provide overall visibility to AEMO.

There are similarities between these approaches and the models that Ofgem in the UK is considering in their Call for Input on the Future of Distributed Flexibility. Ofgem has proposed that that a 'new common digital infrastructure' be established to underpin and enable distributed flexibility to scale.

The point-to-point approach above represents business as usual in the UK; the centralised option is consistent in the UK; and the medium option 'connected to a DER data hub' is similar to Ofgem's medium model 'flexibility exchange'.

Figure 10 | Ofgem proposal for a flexibility exchange as an option for the future of distributed flexibility



Source: Ofgem, Call for Input: The Future of Distributed Flexibility[62]

61 Ofgem. 2023. Call for Input: The Future of Distributed Flexibility. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

62 Ofgem. 2023. Call for Input: The Future of Distributed Flexibility. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

A key difference is that, while Ofgem appears to lean towards the FSO (a possible AEMO equivalent in the UK) as the entity responsible for operating/administering each distributed flexibility market in the exchange, Project EDGE tested a model whereby DNSPs determine the need, source and dispatch NSS for their network via the LSE/flexibility market.

The effectiveness of the Project EDGE approach at scale would depend on the level of standardisation achieved between each LSE/flexibility market. There may also be a case for Australian states with multiple DNSPs to have a single, state-based LSE/flexibility market that is operated by one of the DNSPs or outsourced to a third party (for example, see the case study on NODES in section 7.3.1).

Both the UK and Australia are in the early stages of understanding how common digital energy infrastructure can support DER delivering electricity services, and there are opportunities to share experiences / learnings as each jurisdiction progresses through design stages.

4. Clarity on roles and responsibilities can be a catalyst for capability development

One of Project EDGE's objectives was to develop a detailed understanding of roles and specific responsibilities that each industry actor should play to support DER integration. To achieve this Project EDGE demonstrated working arrangements that leverage existing frameworks, with expanded roles, responsibilities and functions that can be implemented.

While AEMO has statutory functions to operate the wholesale spot market and central dispatch process that considers network constraints (including transmission and distribution),[63] Project EDGE experience has confirmed the broad industry consensus that DNSPs are best placed to manage distribution network constraints through measures such as reflecting those constraints in DOEs.

Project EDGE found that efficient DER integration can be achieved through each industry actor contributing towards the overall optimisation of DER in the power system:

- AEMO co-optimises wholesale energy markets and overall power system security in its role as NEM power system and market operator.
- DNSPs co-optimise distribution network operations to maximise secure network hosting capacity using tools such as DOEs and dynamic management of their network assets. The UoM also identified that DNSPs could play a role in supporting more efficient wholesale market outcomes – for instance, by increasing network hosting capacity during high price events using voltage management.[64] This would represent an evolution from the traditional network management role of DNSPs.

As part of their responsibilities for calculating and communicating DOEs, DNSPs could be accountable for monitoring, and responsible for assessing, conformance to DOEs. DNSPs could choose to obtain monitoring data in different ways, including through metering coordinators. DNSPs could also choose to outsource responsibility to metering coordinators. However, because DNSPs would be setting the DOEs and accountable for assessing conformance, there should be a level of independence with regard to enforcement. Project EDGE identified that there could be three roles relating to DOE conformance:

1. **Monitoring:** collecting data to be used for assessing DOE conformance.
2. **Assessment:** using monitoring data to assess DOE conformance.
3. **Enforcement:** responsibilities of this role could include defining and approving the measures that can be taken when a DOE breach is identified, and may include delegations to enact enforcement measure where appropriate. This role could be done by the AER.

These DOE roles and responsibilities, and the associated processes, will need to be defined by industry policy makers.

- Aggregators co-optimise customer DER operations in line with customer preferences, to 'value stack' and deliver electricity services, sometimes simultaneously. Aggregators also manage potential conflicts to meet all service obligations.

The Project EDGE arrangement of roles and responsibilities underpins the realisation of benefits identified in the CBA.

63 See National Electricity Rules (NER), clause 3.8.1; 3.8.10 and Glossary for the definition of 'network constraints'. https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules

64 VAr is the measuring unit for reactive power. Voltage can be managed via a Volt-VAr curve. It is either the injection or absorption of reactive power. The combination of a configurable array of points define a linear curve that results in the desired Volt-VAr behaviour.

Two major steps remain in defining DER integration roles and responsibilities: agreeing who should operate a DER data hub (if implemented) and, separately, who should operate digital solutions for DNSPs to procure local network services

If a DER data hub is not established, then the digital solutions for DER data exchange will evolve organically with DNSPs developing separate systems to communicate DOEs. Retailers may choose to develop and operate similar solutions to communicate dynamic export limits or use DNSP operated solutions. The Project EDGE CBA showed this could add system costs of $0.44b to consumer bills over a 20-year period, when compared to a DER data hub approach.

If a DER data hub is established, then design choices on governance and operating models will determine whether operational responsibilities are centralised with AEMO or shared.

Similarly, design choices on how to standardise the trade of local network services will determine the operational responsibilities for digital solutions that facilitate the trade of these services.

Concluding remarks

Project EDGE has been a significant undertaking for the Project Participants over the last three years. Participants have conducted the project with a commitment to transparency and collaboration, resulting in a broad portfolio of insights and knowledge for sharing with industry.

The Project EDGE Participants thank all stakeholders who participated, engaged in stakeholder forums and showed an interest in the project. Industry collaboration has been instrumental in shaping Project EDGE, and further industry collaboration will be crucial to build on the EDGE findings and achieving efficient and scalable DER integration within the NEM such that it remains a secure, reliable, affordable and sustainable power system that serves all consumers in a 100GW DER future.

Ultimately, harnessing the capability of coordinated DER to deliver electricity services provides DER customer value, value to all electricity consumers and helps accelerate decarbonisation of the power system by reducing the need for large-scale non-renewable resources.

If challenges with large-scale generation and transmission projects risk delaying the energy transition, investments to accelerate DER uptake and coordination could make DER (and consumers) the hero in meeting net zero.

Project EDGE: **Key Insights and implications for industry**

Project EDGE's field trial, research and analysis have provided important insights and implications for industry. These are outlined in the following table, with further detail provided in the relevant chapters. Insights identified in bold type are recommended by Project EDGE as areas that could be given priority for consideration or action by policy makers and industry.

Table 1: Outline of key insights and implications for industry

Industry actor	Insights and implications for consideration
Consumers (Chapter 2)	
Policy makers	• **Prioritise reforms that enable customers, and the service providers they nominate, to have simple access to real-time data for their DER**
	• **Prioritise DER interoperability reforms that simplify how aggregators integrate new DER into their portfolios to simplify customer switching and enable customer choice**
	• Recognise that social licence is a key challenge for industry and that, if integrating DER into electricity markets at scale is to provide net benefits to all consumers, social licence needs to be developed to prove that customers can trust aggregators to utilise their DER devices in a way that supports system needs but also provides net value to the customer
	• Consider strategies to support the development of DER social licence and collaborate with consumer advocacy groups, market bodies and industry to identify the information and mechanisms that could facilitate the building of DER social licence
	• Consider developing DER export policies that benefit all consumers – with and without DER – through reduced whole-of-system costs, as these may be perceived as fair by most consumers
	• Explore and introduce consistent definitions, frameworks and processes for energy services and markets in which aggregators could participate, as this may assist aggregators to develop commercially viable and compelling incentives that promote greater customer participation and DER activation
	• **When designing electrification incentives, consider that higher DER volumes responding to energy price signals via VPPs can reduce CO2e by displacing technologies with greater emissions intensity**
Aggregators	• **Simplify customer models to sign up to and participate in VPPs and consider how VPP participation can be packaged as part of broader product bundles for customers**
	• **Communicate how customers will be 'better off overall' by joining a VPP**
	• Consider how to build on three key elements to develop commercially viable business models that support power system needs and provide tangible benefits to all consumers: 1 *Value proposition:* The value proposition for joining a VPP should include, and clearly communicate before and after sign-up, tangible financial and non-financial benefits of participation 2 *Motivating a move beyond self-consumption:* Customers are not averse to increasing the amount of power they export through a VPP provided it has been demonstrated they will be better off overall 3 *Social licence:* Transparent communication with readily accessible and easy to understand information can facilitate building the trust consumers need to allow aggregators to utilise their DER
	• Recognise that building a consistent track record of using customer assets while ensuring they are financially 'better off overall' and that their DER is available for customers to use as and when expected will help to build trust
Cost benefit analysis (Chapter 3)	
Policy makers	• **When making decisions, consider the finding of the Project EDGE CBA that four priorities are foundational to unlocking value from DER coordination via VPPs:** - Increasing customer coverage of DOEs - Increased visibility of DER for the market operator and DNSPs. - Implementation of a scalable data hub to support the above - Clear roles and responsibilities where DER aggregators optimise DER on customers' behalf
	• **Prioritise the enablement of flexible export limits to support DOE customer coverage. Dynamic connection agreements can do this if customers are given clear incentives**
	• To promote DOE customer coverage, undertake further work to inform consumers of the benefits of DER integration and to build social licence with customers. Importantly, issues around fairness, transparency of value to customers and trust need to be addressed sufficiently
	• **Work with industry to prioritise implementation of a scalable data hub that provides standardised data services integration, such as DER registration, identity and access management to reduce DER data exchange costs and facilitate improved access to additional DER use cases that can support greater coordination of DER, which drives value to all consumers**
	• Take a targeted approach to implementing advanced DOE configurations and an LSE based on network needs. Barriers to the adoption of an LSE could be lowered by exchanging the data through a scalable DER data hub and standardising its building blocks while still allowing flexibility to define fit for purpose services. It is reasonable to assert that enabling DER aggregators cost-effective access to additional use cases for their DER fleet promotes choice and innovation

AEMO	• Focus on building capabilities relating specifically to DER, leveraging inputs from current reform initiatives such as the proposed 'Integrating price responsive resources into the NEM' ('Scheduled Lite') rule change and DOEs. These capabilities can enable the market operator to know how and in what volumes DER exports will respond to prices and the impact this will have on the market and the ability to forecast effectively. This is aligned with current reform initiatives such as the proposed Scheduled Lite rule change.
DNSPs	• Consider focusing on investment to uplift monitoring and management of their LV networks and connected DER. This will require DNSPs to invest in monitoring systems and digital platforms to increase visibility and control. These investments will be critical to supporting the increased utilisation of network assets and allowing more of the expanding volume of DER to be brought to market • Target implementation of DOEs that are optimised for a given network segment and DER penetration level • Target an approach to LSE implementation that enables scalable and competitive trade of standardised NSS
Dynamic operating envelope design (Chapter 4)	
Policy makers	• **Identify and implement a national approach to implementing DOEs that standardises key elements such as the DOE objective function and communication protocols.** This could include setting out a roadmap of DOE design developments that improve the efficiency of DOEs, with recommended trigger points as DER penetration increases • Recognise that DOE design should start simply and progress to more sophisticated design over time as DER penetration increases • Recognise that DOEs with the objective function of increasing system technical and economic efficiency are likely to provide the most benefits to all electricity consumers in the NEM and could be considered to maximise fairness from a whole-of-system perspective. This aligns to the principles of efficiency for the long-term interests of all consumers in the NEO • **Support DNSP investment in DSO capabilities to rollout DOEs at scale.** This could include reviewing and considering regulatory arrangements to support DNSP investment to develop DSO capabilities and increase spare network capacity to accommodate DER • **Support customers in their choices.** Similar to the findings of the DEIP DOE working group[65] DOEs do not need to be mandated but the customer benefits afforded by choosing a dynamic connection agreement should incentivise widespread uptake when compared to static connection agreements • With substantiation, consider DNSP investment in more accurate DOE calculation capabilities as aligning with the NEO's objectives to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interest of electricity consumers • To align with the regulatory economic framework for DNSP expenditure, consider whether investment in DOE calculation capabilities could be overseen and tested by the AER to ensure it is prudent and efficient, in line with a network's DER penetration levels and network topologies • Consider the use of a DER data hub as a requirement for industry in the future, with the communication of DOEs being the initial primary use case, and collaborate with industry on the design and objectives • **Support further trials and research to test and identify the potential benefits of the different approaches to the DOE allocation point,** recognising that a key decision industry will need to make is the location of the flexible export limit application (the capacity allocation point) • Support and give priority to the AER continuing with its approach to exploring the DOE allocation point as a future action for industry. Considering the forecast uptake of EVs and electrification of the economy, this topic should be considered in the near future to ensure the sector prepares adequately and lays the necessary foundations while network constraints remain manageable, and to provide industry with clarity when developing their capability roadmaps • **Consider whether regulatory change is needed to recognise DNSPs' responsibilities to manage distribution network constraints using DOEs** • **Define and implement a framework to manage DOE conformance and compliance**
DNSPs	• **Engage proactively in efforts to develop a consistent, standardised NEM DOE approach,** recognising that a simple, national approach is in consumers' long-term interests • **Develop their own roadmaps for DOE design developments,** giving consideration to starting with simpler and cheaper DOE design to realise value quickly • **Invest in developing DSO capabilities to support DOE rollout and interactions with DER aggregators around standardised local network support services,** and consider producing DSO action plans to articulate how these capabilities will be developed • Consider investing incrementally in network monitoring and more sophisticated model-based DOE capabilities over time and guided by network topologies and DER penetration levels • **DOE information will need to be shared with customers and third parties transparently.** Customers, and aggregators they nominate will need information on DOEs relevant to their location to make informed choices, and also information on their performance. Further work is required to define what other information customers / aggregators want or need • Work with AEMO to establish a coordinated VPP enrolment / registration process

65 DIEP. 2022. DEIP Dynamic Operating Envelopes Workstream: Outcomes Report. https://arena.gov.au/knowledge-bank/deip-dynamic-operating-envelopes-workstream-outcomes-report/

Wholesale market integration (Chapter 5)	
Policy makers	• **Consider how to progress reforms that would facilitate a stepping-stone approach to DER integration that includes at least four stepping-stones:** 1 Facilitating DER access to off-market revenue opportunities to support aggregator capability maturation 2 Providing visibility through forecasts of anticipated operation (intention of electricity injection or withdrawal at different price points) 3 Passive market participation through bids and offers that don't influence the clearing price calculations but allow aggregators that have demonstrated sufficient capabilities to participate as price takers and self-nominate dispatch targets 4 Graduation to fully scheduled and dispatchable resources
	• **Prioritise simple and cost-effective ways for DER to provide minimum levels of aggregated visibility to AEMO and DNSPs. The 'Integrating price-responsive resources into the NEM' (formerly Scheduled Lite) rule change process is considering some approaches that could be prioritised subject to the rule change assessment and consultation process**
	• Consider developing robust dispatch conformance and compliance frameworks, noting that the results of the Project EDGE field trial indicate the need for appropriate incentives to comply with market requirements and directions
	• **Consider whether regulatory incentives are appropriate for DNSPs to maximise network hosting capacity (demand or generation) during energy market price events**
	• When making decisions, consider the following insights from Project EDGE: - Allow the separate recognition of flexible resources to empower aggregators to develop business models around the DER capacity they can control - Project EDGE field trial results showed that aggregators could develop the telemetry capability needed to participate as scheduled resources in the wholesale market. However, it has to be financially feasible. Cost-effective and secure alternatives to sharing telemetry data via SCADA connections should be considered to enable VPPs to share telemetry with AEMO, DNSPs and TNSPs efficiently
AEMO	• **Consider strategies to help industry develop a robust understanding of the requirements of specific markets and services to ensure VPP systems and processes are developed to conform**
	• Consider providing simple educational information to support new market entrants accelerate their conformance
	• **Develop a detailed roadmap for VPP visibility and dispatchability** that includes a self-dispatch model prior to full dispatchability and identifies the largest possible VPP capacity threshold at which full dispatchability is required in future to support development of roadmaps for VPP capabilities and the enabling policy reform
	• **Streamline market registration and portfolio management processes for VPPs** to enable regular (potentially daily) updates to VPP portfolios
	• **Consider easier ways for aggregators to access energy market data** before becoming market participants; for example, by updating the NEMWeb portal or developing a more streamlined access to this data
	• Recognise that future data communications standards relating to fleets of DER will need to be cognisant of both the power system risks to be managed and the commercial feasibility for aggregators in implementing solutions that comply with these standards
	• When making decisions, consider the following insights from Project EDGE: - Project EDGE field trial results indicate the need for performance testing of aggregators to demonstrate their capabilities to operate under particular market events and with emergency compensatory controls in order to be registered as scheduled resources. Alternatively, other mechanisms would need to be developed or deployed – for example, MSL notices instructing DER generation to turn off or emergency backstop mechanisms - Field trial results also indicate the need for appropriate incentives to comply with market directions - Field trial results showed fleet size needs to reach materiality thresholds to reduce normalised forecasting error. This should be a consideration when setting the thresholds for VPPs to participate as fully scheduled resources - Developing capabilities to meet current operational data communications standards would be too costly for most aggregators in a nascent market. It would likely create barriers to entry. As such, data communications and analysis requirements should be simplified as much as possible while VPPs are small-scale to avoid unnecessary constraints on their growth - The development of fit-for-purpose requirements should be cognisant of system risks, as well as the commercial feasibility to implement solutions. Standards should be proportional to the risk and set the baseline for a level of maturity that needs to be developed over time
	• When defining requirements for visibility of DER, AEMO should consider: - That not all DER responses will be driven by VPPs, for example by DOEs and B2B services such as NSS and retailer hedging - That data streams from VPPs that provide visibility of price-responsive DER capacity should not dictate the market participation model applied to VPPs (at the NMI or behind the meter) - A DER data hub can provide efficiencies in gaining visibility across VPP and non-VPP use cases for AEMO and DNSPs
DNSPs	• Consider collaboration strategies to develop aligned and consistent conformance monitoring and evaluation approaches across DNSPs to support aggregators develop consistent capabilities for DOE conformance – noting that improved DOE conformance is required in a wide-scale rollout of DOEs so DNSPs can rely on DOEs to manage constraints and avoid the need for network solutions that add more costs to customers
Aggregators	• **When developing business models, consider the opportunities to access potential additional revenue avenues from adopting a stepping-stone approach that moves from a self-consumption model to becoming full scheduled resources. This could include participation in FCAS, RERT and off-market business-to-business services to retailers and DNSPs (such as local network support services). This could facilitate building capability and market maturity and provide certainty of return on investment**

Aggregators	• Consider developing business models that provide assurances to customers that net value will be higher from additional trade in VPPs, with the trade-off that the customer may not always be able to self-consume • **Give priority to developing the capabilities necessary for a robust understanding of the requirements of specific markets and services to ensure systems and process are developed to conform in future and avoid costly retrofits and redesign further down the track** • When making decisions, consider the following insights from Project EDGE: - Project EDGE field trial results showed consistent linear ramping is a key capability challenge aggregators will need to overcome to participate in the dispatch process with material capacity portfolios. In Project EDGE, two of the three active aggregators managed to build some linear ramping capability within a few months. This highlights that capability can be developed progressively and supports the need for a stepping-stone approach to aggregator participation as scheduled resources - Field trial results showed fleet size needs to reach materiality thresholds to reduce normalised forecasting error. This should be a consideration for aggregators when developing their business models and considering stepping-stones to developing capabilities toward participation as scheduled resources - To co-optimise services, aggregators would need to develop capabilities and strategies to manage scheduling conflicts among services (e.g. wholesale opportunities conflicting with LSE arming signals) and bid sufficient quantities at price points that would ensure all their service commitments are dispatched, as well as operating their portfolios as multiple sub-fleets (e.g. some DER provide a local network support service response and other DER provide a different wholesale market response where a conflict arises).
Efficient and scalable data exchange (Chapter 6)	
Policy makers	• **Explore the concept of a DER data hub and decide whether a DER data hub approach should be pursued by industry** • **On the assumption a data hub approach is progressed, in collaboration with AEMO, consider whether the DER data hub initiatives in AEMO's NEM2025 Program, specifically the DER Data Hub and Registry Services and Industry Data Exchange projects, are appropriate to support industry collaboration on the development of a DER data hub** • **Link with other activities, such as further investigating Public Key Infrastructure for DER, the national EV mapping tool in the National EV Strategy or the National Charge Link proposal to identify whether integrating initiatives can deliver more efficient outcomes** • **Progress further work on power system architecture with layered intelligence at device level, smart meter level and network level that support 'security by design'** • **Identify appropriate measures to augment cyber security protections for DER and consider including these into a cyber security standard for DER that covers the whole value chain (not just device)**

AEMO	• **If policy makers confirm a DER data hub approach, engage in collaborative planning for a DER data hub through AEMO's NEM2025 Program – specifically the DER Data Hub and Registry Services and Industry Data Exchange projects. Planning activities should include consideration of design principles and policy objectives for a NEM DER data hub; in particular:** 1 Ownership and cost recovery 2 Governance 3 Operation, innovation and development 4 Connectivity and use case • **Collaborate with policy makers to define design principles and policy objectives for a NEM DER data hub** • **Engage in discussion with a broad range of parties in the DER data hub collaboration process to understand the various industry, customer, and other stakeholder perspectives on the concept of a NEM DER data hub** • **Identify appropriate use cases and voluntary participants for a phase 1 implementation** • **Develop detailed design for a minimum viable product** (for phase 1 implementation) that includes Enterprise and Solution Architecture (conceptual and logical). Detailed design should align to the design principles and policy objectives set by policy makers and industry leaders. Detailed design should present technology options suitable for critical infrastructure and should consider the option value of solutions that can enable a transition to alternative approaches as needed in future • **Design a more detailed implementation roadmap** on which use cases could be added and when, in collaboration with industry and in alignment to their needs • Consider requirements for stakeholder engagement and educational materials to explain the need, purpose, objectives and design options for a DER data hub to a broad audience • Collaborate with DNSPs on the design of DER and VPP compensatory controls to avoid duplicate or contradictory controls. The coordination of design should consider the hierarchy of interventions proportional to the magnitude of risk posed to the power system
DNSPs	• **If policy makers confirm a DER data hub approach, engage in the industry discussion to put forward DNSP perspectives on the concept of a NEM DER data hub** • **Collaborate with each other and AEMO to develop an operational procedure between DNSP and AEMO control rooms as DER penetration gains further scale** to communicate compensatory control settings applied and the expected impact of an extended communication outage on coordinated DER operations • Engage with other DNSPs and AEMO to adopt a consistent approach to DER compensatory controls, so DOEs can still be applied even when communications are lost • Collaborate with AEMO on the design of compensatory controls to avoid duplicate or contradictory controls. The coordination of design should consider the hierarchy of interventions proportional to the magnitude of risk posed to the power system

	• Collaborate with each other and AEMO to agree different default DER control settings to apply under different seasons or operating conditions, if appropriate
	• Collaborate with each other and AEMO to agree appropriate testing and conformance monitoring approaches for compensatory controls settings for VPPs and DOE-enabled devices.
Aggregators	• **Engage in the industry discussion to put forward aggregator perspectives on the concept of a NEM DER data hub**
	• Engage with DNSPs and AEMO to agree appropriate compensatory control settings and approaches
Local network support services (Chapter 7)	
Policy makers	• **Consider an industry-wide approach to standardisation of local network support services** that covers common service definitions, contractual terms and the way services are transacted, while leaving flexibility for DNSPs to develop additional bespoke services to meet local network topographies and needs. Standardisation should also not hamper innovation by first movers
	• Consider developing standardised frameworks to enable the trade of local NSS to facilitate scale across DNSP service areas, noting that performance data from the Project EDGE field trials show technical capability (at small-scale) to manage network reliability through the provision of local NSS from DER and that lessons learnt in the UK indicate the development of scaled NSS trade needs to be facilitated through more standardisation, simplification and transparent decision-making
	• Recognise that broad engagement and commitment to implementation will be needed across industry – including policy makers, DNSPs and aggregators – to ensure a direct correlation between the level of standardisation across regions and scalability of local NSS
	• **Further explore a Local Services Exchange framework connected to a DER data hub model to facilitate procurement of NSS and VPP participation to begin scaling.** Consideration should be given to potential integration points such as standing data, telemetry and control signals. The framework should be linked to national mapping of EV charging infrastructure to identify opportunities for synergies.
	• Consider developing a framework for local NSS now, so that efficient mechanisms are in place as DER scales – noting that in the short term, DER penetration may only be sufficient in localised areas to support participation in an LSE
	• **In designing an LSE framework, confirm whether DNSPs are the appropriate industry participant to operate LSE platforms** and consider how TNSPs could use the LSE to procure network support services in the future
	• **Consider whether regulatory incentives are strong enough to encourage greater use of network support services**
DNSPs	• **Engage proactively with policy makers, aggregators and other DNSPs in developing consistent approaches to network support services**
	• **Consider development of an industry guideline to standardise (or provide guidance on standardising as much as possible) the characteristics and lifecycles of local network support services** and transaction terms (e.g. common service definitions, contractual terms and the way that services are transacted)
	• **Engage pro-actively in developing consistent approaches to the provision of detailed information on forecast network constraints** to enable aggregators to develop strategies to support the delivery of network support services
	• Recognise that broad engagement and commitment to implementation will be needed across industry – including DNSPs, aggregators and policy makers – to ensure a direct correlation between the level of standardisation across regions and scalability of local NSS
	• Consult with other industry participants on setting compliance thresholds in a way that balances network congestion management and the uptake of LSE services by aggregators
Aggregators	• Consider participation in providing local NSS as a potential stepping-stone in their product roadmaps to access revenue to develop capabilities and systems to graduate to fully scheduled resources
	• When developing strategies for participation in the delivery of local NSS, carefully consider the key factors aggregators need to manage or mitigate impacts to successful delivery
	• Actively participate in consultation on setting compliance thresholds
Roles and responsibilities (Chapter 8)	
Policy makers	• Consider a review of the NEM's legal and regulatory framework to ensure clarity of roles and responsibilities and risk allocation if DNSPs are calculating distribution constraints while AEMO is responsible for maintaining system security
	• Consider developing and implementing a robust DOE conformance monitoring and compliance framework that separates duties in terms of DOE conformance monitoring, DOE conformance assessment and DOE compliance enforcement
	• If a common industry data exchange infrastructure is deemed suitable for DER, consider design principles and policy objectives to determine who should be responsible for operating and governing the digital solutions that support this
AEMO	• Further consider approaches and mechanisms for VPP level DOE conformance monitoring and the management of transmission level constraints in a high DER future where VPPs reach material scale across a state and a concentration of resources in a particular area may impact transmission constraints at certain times
	• Note the results of the Project EDGE field trial, which showed that AEMO does not need to be responsible for co-optimising DER services in a future system where DER are integrated into electricity markets. AEMO can continue to co-optimise wholesale services dispatch (energy and FCAS). Aggregators are best placed to co-optimise DER services (such as providing wholesale services while simultaneously delivering local network services)

DNSPs	• **Collaborate with policy makers and AEMO to develop a DOE conformance and compliance framework**
	• Participate in the exploration of approaches and mechanisms for VPP level DOE conformance monitoring that provide AEMO with confidence it can dispatch aggregator bids that will not materially impact distribution network limits
Aggregators	• Note the results of the Project EDGE field trial, which showed that in a future system where DER are integrated into electricity markets, aggregators are best placed and able to co-optimise DER services (such as providing wholesale services while simultaneously delivering local network services)
DNSP investment and capability (Chapter 9)	
Policy makers	• **Continue the effort to adopt a national approach to the DOE rollout, as first raised in the DEIP DOE Outcomes report**
	• **Consider requesting the AER to lead collaboration with industry and market bodies to develop an appropriate definition of the Australian DSO role and the capabilities required, and the trigger points for when they are needed**
	• After the DSO role is defined, support industry collaboration to identify and technically define necessary DSO capabilities and the progressive uplift in DNSP capability required over time
	• After the DSO role is defined, review regulatory mechanisms to ensure appropriate incentives for DNSPs to implement DSO capabilities that can deliver benefits to all consumers
DNSPs	• **Develop appropriate capabilities to support the implementation of DOEs and facilitate DER participation in energy markets and service provision.** In doing so, DNSPs should consider: - Developing their own roadmaps appropriate to their network needs - Adopting a targeted approach to investment based on DER penetration in their networks and aligned with the AER's regulatory economic framework.
	• Develop further DSO capabilities to procure network support services from DER
	• Proactively participate in industry collaboration with the AER and market bodies to identify a consistent definition of the DSO capabilities required and the trigger points for when they are needed

INTRODUCTION

1.1 Introduction

Australia's National Electricity Market (NEM) operates on one of the world's longest interconnected power systems, spanning the nation's eastern and south-eastern coasts and comprising five interconnected regional markets: Queensland, NSW (including the ACT), Victoria, South Australia and Tasmania. The NEM serves around 10.7 million customers and supplies about 200 terawatt hours (TWh) of electricity to businesses and households each year.[66] The NEM is overseen by the Australian Energy Market Operator (AEMO).

The NEM is undergoing a rapid transformation and facing new challenges as Australia's energy landscape changes, with industry and households drawing on electricity in place of oil and gas for their daily energy needs, legacy assets being replaced with renewables, more storage and other forms of firming capacity being added, and a reconfiguration of the grid to support new power sources in new locations and two-way energy flow.

> DEFINITION
> **Distributed Energy Resources (DER)**
>
> **Distributed Energy Resources (DER)** are devices connected to the distribution network that can generate or store electricity, or that have the 'smarts' to actively manage energy demand.

One critical challenge for the NEM is how to integrate increasing numbers of Distributed Energy Resources (DER) in a way that is fair and secure, and that benefits everyone.

Australia already leads the world in the uptake of DER and demand for DER is expected to continue to grow. Without effective action, the scale of the shift to DER will have a material impact on the dynamics and security of the NEM. Insufficient action will also likely result in higher costs of electricity supply for consumers, just as they are transitioning to EVs and replacing gas-fuelled appliances with electric alternatives.

Finding solutions to integrate and coordinate high levels of DER within the NEM is critical not only to supporting an affordable and reliable electricity supply, but also to reducing the need for additional investment in large-scale generation resources and network infrastructure.

Making a successful transition to a high DER future for the NEM also offers potential economic benefits for DER customers and electricity consumers more broadly, as well as bringing opportunities for consumers to access new products and services,

Project EDGE (Energy Demand and Generation Exchange) has been undertaken to explore solutions to integrate and coordinate DER into the NEM. This final knowledge sharing report synthesises the many learnings and insights from Project EDGE across its three-year duration. The report presents the key findings from Project EDGE for consideration by industry and policy makers in the ongoing reform and design of the NEM for DER integration.

1.2 About the National Electricity Market

The NEM stretches across a distance of around 5,000 kilometres, extending from Port Douglas in far north Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania, and incorporating five interconnected states. The NEM's transmission network carries power from electricity generators to large industrial energy users and local electricity distributors across the five states. These assets are owned and operated by state governments or private businesses.

1.2.1 How the NEM works

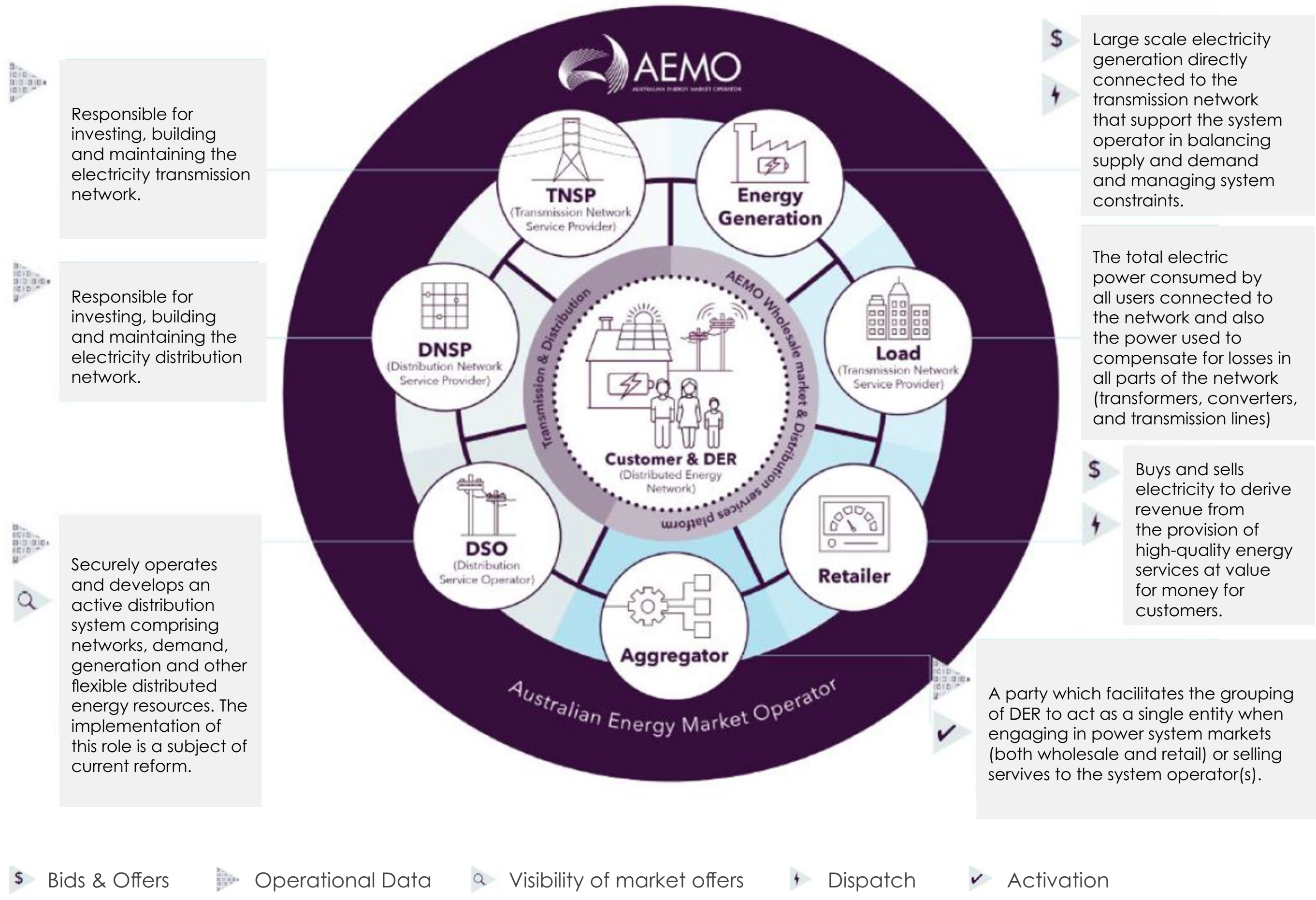
The NEM commenced operation in December 1998 and is facilitated through a wholesale energy-only or 'spot' market, where the output from all generators is scheduled and sold at five-minute intervals to meet demand. The National Electricity Rules set a maximum dispatch (or spot) price, which is adjusted annually for inflation. The Rules also set a minimum spot price.

In the wholesale market, generators sell electricity and retailers buy it to on-sell to consumers. To pay generators, AEMO recovers costs from customers. Most customers purchase their electricity through a retailer, paying the retailer a commercial tariff. Retailers manage their customers' energy purchases and pay AEMO the spot price.

The NEM is a largely de-regulated market, which means different participants own and operate different parts of the electricity supply chain. 11 summarises the roles and responsibilities of different participants in the NEM.

> DEFINITION
> **Wholesale energy 'spot' market**
>
> The electricity market works as a 'pool', or 'spot' market, where power supply and demand is matched instantaneously in real time through a centrally coordinated dispatch process.

Figure 11 | Roles and responsibilities of AEMO and participants in the NEM



Source: AEMO

66 AEMO. 2021. Factsheet: The National Electricity Market. https://aemo.com.au/-/media/files/electricity/nem/national-electricity-market-fact-sheet.pdf

1.2.2 Distributed Energy Resources in the NEM

The NEM is rapidly transforming towards a decentralised, two-way energy system, driven by Australia's uptake of DER. The NEM already hosts over 15GW of rooftop PV, which is collectively the largest generator in the NEM.[67]

AEMO's 2022 Integrated System Plan (ISP), which provides a whole-of-system roadmap for the ongoing development of the NEM, anticipates a 'decentralisation, digitalisation and democratisation' of the NEM by 2050 under the step change scenario.[68] Stakeholders engaged in the development of the 2022 ISP identified 'step change' as the most likely scenario.

Under this scenario, AEMO estimates that by 2050:[69]

- Over 100GW of DER are expected to be connected to the NEM, representing 40% of total NEM installed capacity.
- This includes 69GW of residential rooftop PV capacity, with more than 60% of the homes in the NEM likely to have rooftop PV (compared to approximately 30% of homes today).
- Coordinated DER storage of 31GW (including 7GW of V2G EVs) may represent almost half of total dispatchable storage capacity.

DEFINITION
Coordinated DER

Coordinated DER refers to DER that are integrated and responsive to power system and market needs; that is, DER that are visible, predictable and operable within the NEM.

This high level of DER penetration creates the need to ensure that the power system and millions of DER installations can operate together. If it is not coordinated, this amount of DER storage operating dynamically may cause material swings in the supply-demand balance in the NEM that are difficult to forecast and manage.[70], resulting in detrimental outcomes for all consumers. Specifically, a higher cost electricity system and greater risk of blackouts.

1.3 Origins of Project EDGE

Considerable work is underway across a number of areas and organisations to develop new ways to understand and manage the effect of high levels of DER in different parts of the electricity grid.

Project EDGE (initially referred to as the Victorian Distributed Energy Resources Marketplace Trial) was originally proposed following the Open Energy Networks Project (OpEN). A collaboration between AEMO, Energy Networks Australia (ENA) and stakeholders from across the energy industry, OpEN sought to identify the most appropriate framework for building a two-sided marketplace that can better integrate DER into local distribution networks.[71]

OpEN investigated solutions to optimise and manage DER on the distribution network, and to facilitate DER participation in the wholesale energy markets. A Hybrid model was identified as the most appropriate framework, in which market operation functions are allocated to a single entity (AEMO) and Distribution Network Service Providers (DNSPs) optimise the operation of their distribution systems. However, OpEN recognised that there is no single definition of the Hybrid model and that trials would be needed to understand the most effective pathways to implementing the model and to optimise its efficiency and benefits for industry and consumers.[72]

67 AEMO. N.d., DER Register Data. https://aemo.com.au/energy-systems/electricity/der-register/data-der/data-dashboard

68 AEMO. 2022, 2022 Integrated System Plan, p 9; p 54. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

69 These estimates occur under the 'step change' scenario set out in the AEMO 2022 Integrated Service Plan (ISP), identified by stakeholders engaged in the development of the ISP as the most likely scenario.

AEMO. 2022, 2022 Integrated System Plan, p 9. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

70 AEMO. 2019, Technical integration of Distributed Energy Resource April 2019 - Improving DER capabilities to benefit consumers and the power system: A report and consultation paper. https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf

71 AEMO and ENA. 2019, Open Energy Networks Interim Report: Required Capabilities and Recommended Actions. https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

72 AEMO and ENA. 2019, Open Energy Networks Interim Report: Required Capabilities and Recommended Actions. https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

AEMO, AusNet Services and Mondo (Project Participants), with funding from the Australian Renewable Energy Authority (ARENA), designed Project EDGE to build on OpEN by field trialling how AEMO and DNSPs can collaborate in a Hybrid model and develop an evidence base by moving from theory to practice with real customers and real assets, in order to inform regulatory reforms, industry capability development, investment decisions and innovation.

1.4 About Project EDGE

1.4.1 Objectives and research questions

Project EDGE sought to demonstrate an off-market, proof-of-concept two-sided arrangement (the Hybrid model described in section 1.3 above) in which electricity market participants coordinate DER to provide wholesale services and local network support services within the constraints of the distribution network.

The Project Participants designed EDGE as a research project to support cross-industry decision making with evidence by implementing and trialling an end-to-end market-based arrangement for DER integration that is substantially aligned with industry thinking and concepts in the DER Implementation roadmap developed by the Energy Security Board (ESB).[73] EDGE findings are based on real-world scenarios and how the current NEM arrangements work, and as such, they are practical rather than purely academic or hypothetical scenarios. This was intentional so that the findings could lead to real change in the NEM rather than being theoretical or disconnected from the current reality and therefore difficult to implement. The Project Participants applied a design thinking hierarchy or cascade that aimed to link every aspect of the Project EDGE design back to the NEO.[74]

73 ESB. 2021, DER Implementation Plan activities for Horizon One: Attachment C. https://www.datocms-assets.com/32572/1639638288-attachment-c-der-implementation-plan-reform-activities-for-horizon-one-december-2021.pdf; ESB. N.d., DER Implementation Plan – reform activities over three-year horizon. https://www.datocms-assets.com/32572/1639638279-attachment-a-der-implementation-plan-three-year-horizon-december-2021.pdf

74 The National Electricity Objective is one of three National Energy Objectives. The National Electricity Objective is stated in the National Electricity Law.

Figure 12 | Project EDGE design thinking cascade

NEO

To promote investments in, and efficient operation and use of electricity services in the long term interests of consumers of electricity.

Problem statements

Engaging stakeholders to understand their perspectives on what is required to enable DER to efficiently deliver wholesale and local network services at scale and develop clear problem statements.

EDGE objectives

Stakeholder perspectives and problem statements were used to define Project EDGE objectives that could demonstrate technical requirements but also enable evidence produced to inform regulatory forms and industry development.

EDGE research questions

Various high-level research questions were drafted in the early stages of Project EDGE, which were refined to through stakeholder engagement down to 7 prioritised research questions and associated hypotheses.

EDGE design principles

For each of the three core function sets of the DER Marketplace concept, the EDGE Project Partners agreed some design principles that should guide the detailed design process.

EDGE design

The project EDGE partners collaboratively designed each element of the DER Marketplace over a series of workshops, which then enabled them to develop detailed requiremenrs for their own systems/capabilities.

Requirements

Detailed requirements developed by each Project Partner for the systems and capabilities that collectiverly make up the DER Marketplace were informed by the design thinking cascade, starting with the NEO.

Further details about this cascade and the stakeholder problem statements are provided in the research plan produced by the University of Melbourne (UOM).[75]

The Project Participants agreed on ten objectives for Project EDGE, outlined below.

Figure 13 | Project EDGE objectives

MARKETPLACE TECHNICAL REQUIREMENTS

1 **Wholesale market participation enabled at scale**
Demonstrate how DER fleets could participate in existing and future wholesale energy markets at scale

2 **Distribution network limits in wholesale dispatch considered**
Demonstrate different ways to consider distribution network limits in the wholesale dispatch process.

3 **Efficient and scalable trade of local network services enabled**
Demonstrate how to facilitate standardised. scalable and competitive trade of local network services.

4 **Efficient, scalable and secure data exchange enabled**
Demonstrate how data should be exchanged efficiently and securely between interested parties to support distributed energy services.

5 **Integrated technology**
Develop a proof of concept, integrated software solution to facitate delivery of objectives 1-4 in an efficient and scalable way

ENABLERS FOR IMPLEMENTABLE REFORM

6 **Defined roles and responsibilities**
Develop a detaied understanding of roles and specitic responsibilities that each industry actor should play

7 **Cost-benefit analysis**
Conduct comprehensive cost-benefit analysis to provide an evidence base for future regulatory decision making

8 **Customer perspective engaged**
Conduct a customer focused social science study to understand customer opinions on the complexities of DER integration.

9 **Stakeholders engaged according to best practice principles**
Deliver best practice stakeholder engagement throughout the project with a commitment to knowledge sharing

10 **Evidence- based implementation recommendations**
Deliver recommendations, supported with evidence, on how and when the concepts demonstrated should be implemented operationally

These objectives then informed the research questions and underlying hypotheses.

75 UOM. 2022. Project Edge Research Plan. https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35

Figure 14 | Project EDGE research questions and hypotheses

Research questions		Summary of hypotheses	Related objectives
CUSTOMER	**RQ1. How can the DER marketplace be designed to enable simple customer experiences, deliver the needs of customers and improve social license for active DER participation?**	a) Customers to invest in DER to participate in the DER markeplace are influenced by multiple factors b) Customers are willing to participate if offers are simple and provide sufficient value ove time. c) Minimising complexity enables aggregator participation and enables provision of value	**1, 3, 8**
CBA NEO	**RQ2. Does the DER Marketplace promote efficient investment in efficient operation and use of electricity surfaces for the long-term interests of consumers?**	a) A DER Marketplace can deliver net positive economic benefits for all consumers b) Local services exchange enables DNSP network deferral c) A data hub model provides a cost-efficient, scalable and simple approach to data exchange. d) Roles and responsibilities of actors are largely aligned to current roles.	**1, 3, 4, 6, 7**
OPERATING ENVELOPE DESIGN	**RQ3. How does operating envelope design impact on the efficient allocation of network capacity while enabling the provision of wholesale energy and local network services?**	a) Operating envelope design has a material impact on network operation and efficient services. b) Technical and economic outcomes improve when uncertainty is accounted for in the calculation of operating envelopes. c) Efficiency of operating envelope design and implementation can increase as DER uptake increases. d) Network capacity allocation should focus on maximising utilisation and yielding highest net economic benefit for all consumers. Fairness is best achieved ex-post and not through envelopes.	**1, 2, 3, 7**
WHOLESALE INTEGRATION	**RQ4. How can the DER Marketplace facilitate efficient activation of DER to respond to wholesale price signals, operate within network limits and progress to participation in wholesale dispatch over time?**	a) DER participation in wholesale market can be achieved progressively and align with ESB reforms. b) System Operator and DNSP interactions can be defined and implemented efficiently to maintain DER within limits at all times. c) The aggregator should be responsible for ensuring DER value stack instead of the market operator co-optimising services.	**1, 2, 3, 6**
LOCAL NETWORK SERVICES	**RQ5. How can the DER Marketplace facilitate efficient and scalable provision of local network support services from DER so that network efficiency benefits are realised for all customers?**	a) Network reliability can be managed through local network services from customer DER. b) DNSP barriers to relying on local network services from DER can be overcome through procurement mechanisms. c) Local network services characteristics and procurement can be standardised across regions.	**3**
EFFICIENT DATA EXCHANGE	**RQ6. What is the most efficient and scalable way to exchange data between industry actors, considering privacy and cyber security, to benefit all consumers?**	a) A data hub model provides a cost-efficient, scalable and simple approach to data exchange. b) Decentralised digital infrastructure with appropriate security and governance provides efficiency and participation opportunities and can address risks. c) AEMO and DNSPs need to develop capabilities that maintain a secure and resilient power system and distribution network respectively.	**4, 5, 6**
DNSP INVESTMENT AND CAPABILITY	**RQ7. How could DNSP investment to develop DSO capabilities improve the economic efficiency of the DER Marketplace?**	a) There is an optimal combination of DNSP investment in network and DER based non-network solutions that provides higher economic efficiency and improved operation of the DER Marketplace as DER increases	**1, 6, 7**

Project EDGE objectives

1	Wholesale market participation enabled at scale	2	Distribution network limits in wholesale dispatch considered	3	Efficient and scalable trade of local network services	4	Efficient, scalable and secure data exchange enabled	5	Integrated technology
6	Defined roles and responsibilities	7	Cost-benefit analysis	8	Customer perspective engaged	9	Stakeholder engaged according to best practice principles	10	Evidence-based implementation recommendations

Customer | Wholesale market integration | Local services | Efficient data exchange

1.4.2 Approach to addressing research questions

The Project Participants adopted a structured approach to addressing the research questions by planning and implementing various activities including:

- Literature review, case studies and stakeholder engagement / interviews
- Customer insights surveys
- Cost benefit analysis
- Field testing and subsequent data analysis
- Techno-economic modelling and analysis.

The field trial portion of Project EDGE formed the central part of the program. The project tested different approaches to delivering four essential DER integration functions: wholesale market services, local distribution constraints, data exchange and network support services. These functions were tested within a trial version of the NEM to investigate how price-responsive DER can be integrated into current market arrangements, rather than having a separate electricity marketplace for DER.

These concepts were trialled in an off-market environment over 333 days of continuous 24x7 market operations, observing Virtual Power Plant (VPP) behaviour against live forecast and actual NEM regional spot prices. This allowed Project EDGE to collect a rich and representative dataset across both 'system normal' conditions and scripted scenarios based on historical events that tested relatively rare but high impact power system events in the field.

The Project EDGE field trial cycled through a number of pre-determined 'modes' to isolate and test a variety of variables including:

- DNSP dynamic operating envelope (DOE) implementations by frequency, calculation approach, whether it comprises active power or both active and reactive power, and objective function.
- Aggregator bidding approaches, with different bidding quantity definitions and bidding approaches (such as visibility without dispatch instructions, self-dispatching by providing self-nominated dispatch targets and scheduled with active market participation).

DEFINITION

Dynamic operating envelope (DOE) and Aggregator

Dynamic operating envelope (DOE) refers to the limits on the amount of electricity that a customer can import from and export to the distribution grid at a point in time. The limits (operating envelope) can vary according to the prevailing grid conditions (that is, they are dynamic).

As the network's hosting capacity is finite and only increases through traditional augmentation. DOEs enable more efficient use of that hosting capacity by allowing DNSPs to vary customer exports dynamically depending on network conditions.

Aggregator refers to entities that represent small-scale DER from many customers. Aggregators collectively manage these devices as a Virtual Power Plant (VPP) to provide larger scale electricity services for power system and distribution network operations and electricity markets.

The individual mode characteristics are outlined in Table 2. Each mode consisted of a combination of characteristics.

Table 2: Characteristics of modes tested in the Project EDGE field trials

Characteristic	Description
DOE frequency	The frequency of DOE calculation and transmission. This is ether a day-ahead of trading day, or intra-day.
DOE calculation (see section 4.3.3)	The approach used to calculate DOEs. This is either both the low voltage (LV) network model and approximation algorithm, or only either the approximation algorithm or the LV network model.
DOE active vs reactive	Whether the DOE comprises active power or both active and reactive power.
DOE objective function (see section 4.3.2)	The objective function of the DOE calculation. Most field trials were based on an objective function to 'maximise aggregate export service'. However, 'equal allocation' was also tested.
Bidding type (see section 5.3.2.2)	The same bid file would be used for different types of bidding providing a 48 hour rolling window every 5 minutes: • Visibility: Bidding provided for operational visibility. Aggregators are not required to act on or respond to dispatch instructions • Self-dispatch: Passive market participation and prices submitted using the energy fixed loading (EFL) field. This means the aggregator self-nominates a dispatch target for the dispatch interval which does not influence the clearing price calculation • Scheduled: Active market participation using price quantity pairs across 20 bands with price setting bi-directional offers.
Bidding quantity definition (see section 5.3.2)	This is the definition of where the offering quantity is measured. It is either the aggregated net connection point flow measured at the National Meter Identifier (the individual connection point with the distribution network), also known as Net NMI, or it is the aggregate of all controllable devices measured at a real or virtual measurement point (Flex).
Dispatch instructions	AEMO would generate and send dispatch instructions every 5 minutes based on aggregator bids. The bidding characteristic would determine if aggregators were required to act on and respond to the dispatch instructions.

Field trials also tested several scripted scenarios to ensure the results included data on performance under important market conditions. The scenarios included:

- DER energy arbitrage to test how aggregators behaved and responded to both forecast and sudden price spikes, high price volatility and lack or reserve and minimum system load days
  - The purpose of these scenarios was to test aggregators' ability to respond to price events with a high level of accuracy to their scheduled dispatch targets, determine whether aggregators could coordinate DER fleets to respond instantaneously to negative or high price events, and to better understand contingency events for improved forecasting of VPP behaviour
- Aggregators' response to communication failures, such as the loss of connection between aggregators and AEMO, between aggregators and their DER portfolios, and between DNSPs and AEMO
  - The purpose of these scenarios was to understand how aggregators performed during communication outages, inform the optimal default operational arrangements under loss of communications, and understand the impact of communication failures on market outcomes.

Although the testing area in north-east Victoria and number of participants was relatively small compared to the NEM, Project EDGE tested an end-to-end lifecycle for DER participating in local and wholesale energy services with a rich sample set. A field trial that ran 24/7 for 333 days, using real forecast and actual market prices for Victoria, real-world scenarios, and over 320 residential and commercial participants (with 3.5MW+ of flexible capacity), represented a diverse mix of:

- Market price conditions
- Real-world scenarios, including failure scenarios such as communication losses
- Customers
- Retailer and third-party aggregator business models
- DER equipment
- Manufacturers
- DER control device systems.

Participants included both retailer and behind-the-meter aggregators, with more than 400 DER assets including rooftop PV, batteries, controlled hot water systems and other loads.

Field trials also tested several scripted scenarios to ensure the results included data on performance under important market conditions. The scenarios included:

- DER energy arbitrage to test how aggregators behaved and responded to both forecast and sudden price spikes, high price volatility and lack or reserve and minimum system load days
  - The purpose of these scenarios was to test aggregators' ability to respond to price events with a high level of accuracy to their scheduled dispatch targets, determine whether aggregators could coordinate DER fleets to respond instantaneously to negative or high price events, and to better understand contingency events for improved forecasting of VPP behaviour
- Aggregators' response to communication failures, such as the loss of connection between aggregators and AEMO, between aggregators and their DER portfolios, and between DNSPs and AEMO
  - The purpose of these scenarios was to understand how aggregators performed during communication outages, inform the optimal default operational arrangements under loss of communications, and understand the impact of communication failures on market outcomes.

To isolate variables, the trial was organised by the modes discussed earlier and shown in Table 2.

For each core element of this end-to-end lifecycle, Project EDGE adopted various approaches that together form a rich evidence base to inform industry decision making:

- *Customer insights:* an extensive program of customer surveys and interviews to understand customer needs and experiences, covered in Chapter 2
- *Dynamic operating envelopes:* various methodologies to calculate and communicate DOEs, including options for future design improvements, covered in Chapter 4
- *Wholesale market integration:* different approaches to DER wholesale market integration, with progressive levels of participation, covered in Chapter 5
- *Scalable DER data exchange:* different technology models for operating an industry DER data hub (centralised and decentralised models), covered in Chapter 6
- *Local network support services:* multiple designs for standardised local network support services, covered in Chapter 7.

We would like to congratulate the Project team on a well-run trial and the associated systematic and comprehensive tests. The number and quality of these tests has exceeded by far the requirements and expectations set out by the UOM team when we developed the research plan, thus underscoring the robustness of the field trial and, by extension, of the relevant evidence it has generated.

- The University of Melbourne

1.4.3 **Commitment to transparency and knowledge sharing**

Objective number nine for Project EDGE was to ‘Deliver best practice stakeholder engagement throughout the project with a commitment to knowledge sharing’. To meet this objective, the Project Participants delivered a broad program of stakeholder engagement and knowledge sharing.

Figure 15 | Summary of Project EDGE engagement forums and knowledge sharing

Project EDGE Objective 9

Deliver best practice stakeholder engagement throughout the project with a commitment to knowledge sharing.

Forums

- DER Demonstrations Insights Forum [AEMO] — MONTHLY
- Network Advisory Group [AusNet] — MONTHLY
- DER Market Integration Consultative Forum [AEMO] — MONTHLY
- Consumer Advisory Group [Mondo] — MONTHLY

Conference Presentations

- International Global Power System Transformation Consortium — MAR ‘22
- Energy Systems Integration Group — MAR ‘22
- ARENA DEIP Dive 1: EV and DER Market Integration Event — SEP ‘22
- 9th International Congress for Integration of Renewables & DER — OCT ‘22
- International Association of Power Exchanges — OCT ‘22
- ARENA DEIP Dive 2: EV and DER Market Integration Event — JUL ‘23

Technical Specifications

- 17 Technical Specifications — JAN ‘22

Knowledge Sharing Reports

- Lessons Learned Report #1 — MAY ‘21
- EDGE MVP Demonstration Use Cases — DEC ‘21
- Research Plan — MAR ‘22
- Interim Customer Insights Report — JUN ‘22
- Interim Report — JUN ‘22
- CBA Methodology Consultation — JUL ‘22
- Customer Insights Literature Review — OCT ‘22
- Community Perceptions of DER and Aggregated Services — NOV ‘22
- CBA Methodology — DEC ‘22
- Lessons Learned Report #2 — DEC ‘22
- Qualitative Insights for Customers in a VPP — MAY ‘23
- Technology & Cyber Assessment — MAY ‘23
- Fairness in DOE Objective Functions — JUN ‘23
- Survey Insights for Customers in EDGE VPPs — JUN ‘23
- Customer Insights Study Summary Report — JUN ‘23
- DER Data Exchange Lessons Learned — JUN ‘23
- Determining the Impact of Update Frequency on Operating Envelope Efficacy — AUG ‘23
- Testing Different DOE Approaches at DER Penetration Levels in Real-World Networks — AUG ‘23
- Final CBA Report — OCT ‘23
- FInal Knowledge Sharing Report — OCT ‘23

Public Webinars

- EDGE Webinar #1 — MAR ‘21
- Minimum Viable Product Showcase — DEC ‘21
- Customer insights Interim Webinar — JUN ‘22
- Interim Report Webinar — JUN ‘22
- Customer insights Final Webinar — JUN ‘23
- CBA Webinar — OCT ‘23
- Final Report Webinar — OCT ‘23

The range of publications produced by Project EDGE represent a substantial volume of learnings and insights that can be used to inform how to integrate DER efficiently into electricity markets, as well as providing lessons for measures to avoid.

More than 150 formal stakeholder engagements were held as part of the project. These included showcases and discussions on the research plan questions and hypotheses, design options, approaches, interpretation of preliminary results and the validation, categorisation and prioritisation of data exchange problem statements and use cases. Forums were interactive and covered a broad range of industry participants including network service providers, community stakeholders from the Hume region (where the trial took place), aggregators, retailers and regulatory bodies.

Stakeholder engagement also included deep-dives into the analysis of preliminary data with the aggregators participating in the field trials to better understand the context of the results and identify key implications.

The significance of Project EDGE’s research and knowledge sharing on DER integration to electricity markets was highlighted by the project presenting to the 9th International Conference for Integration of Renewable and Distributed Energy Resources (IRED).[76] IRED is a global conference of experts from industry, government and academia to share knowledge on DER integration. The conference at which Project EDGE presented focused on the technical, market and regulatory issues and challenges to integration of DER into the grid.[77]

1.5 **Robustness of insights and considerations in this report**

Recognising that policy reform does not often have the benefit of practical evidence to inform its design, the EDGE team designed the research program to produce an evidence base that was robust and reliable. The practical evidence from the field trials, the desktop research and literature reviews, specialist modelling and extensive stakeholder engagement have provided a wealth of findings and insights. Combined with practical learning from the detailed design process and end-to-end implementation of the off-market trial, the findings and considerations offered to industry in this report are sufficiently robust to help inform the design and implementation of DER integration reforms.

1.6 **Further areas for research**

Project EDGE has undertaken comprehensive research on the functions and capabilities needed to integrate DER into the NEM. Through the trial and from analysis of the findings, the Project team also identified certain topics that could not be included within the scope of the trial but that warrant further assessment and analysis in future trials or studies.

These topics represent additional considerations to integrate DER effectively and efficiently at scale. While Project EDGE explored some findings and insights for these features, they have not been trialled and further research is required to fully understand their potential value, and relevant implications for DER market arrangements. These further areas for research are identified in the Next steps sections of the relevant chapters.

76 Project EDGE. 2022, Project EDGE – DER Marketplace Demonstration March 2022 https://aemo.com.au/-/media/files/initiatives/der/2022/esig-presentation.pdf?la=en

77 IRED. N.d., 24-26 October 2022 Adelaide, South Australia. https://ired2022.com.au/

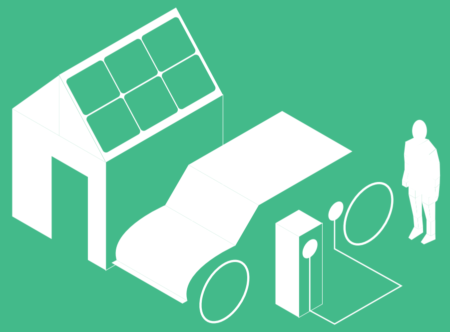
1.7 Guide to this report

Each of the research questions that were established as foundational elements of Project EDGE (see Figure 12) are addressed in a distinct chapter of the report, with an additional chapter focused on roles and responsibilities. The report is structured as follows:

- **Chapter 2: Customer needs and experiences**
  - Research question: How can integrating DER into the NEM be designed to enable simple customer experiences, deliver the needs of customers and improve social licence for active DER participation?
- **Chapter 3: Cost benefit analysis**
  - Research question: Does the integration of DER into the NEM promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers?
- **Chapter 4: Dynamic operating envelope design**
  - Research question: How does operating envelope design impact on the efficient allocation of network capacity while enabling the provision of wholesale energy and local network services?
- **Chapter 5: Wholesale market integration**
  - Research question: How can integrating DER into the NEM facilitate efficient activation of DER to respond to wholesale price signals, operate within network limits and progress to participation in wholesale dispatch over time?
- **Chapter 6: Efficient and scalable DER data exchange**
  - Research question: What is the most efficient and scalable way to exchange data between industry actors, considering privacy and cyber security, to benefit all consumers?
- **Chapter 7: Local network support services**
  - Research question: How can integrating DER into the NEM facilitate efficient and scalable provision of local network support services from DER so that network efficiency benefits are realised for all customers?
- **Chapter 8: Roles and responsibilities**
  - Roles and specific responsibilities that each industry actor should play in the integration of DER into the system and electricity markets
- **Chapter 9: DNSP investment and capability**
  - Research question: How could DNSP investment to develop DSO capabilities improve the economic efficiency of the integrating DER into the NEM?

For ease of reference, each chapter that relates to a research question follows the same structure:

- **Overview:** Succinct summary of the key findings and insights discussed in the chapter
- **Context:** DER integration challenges associated with each topic
- **Approach:** How Project EDGE tested mechanisms to address these challenges
- **Findings:** Further detailed analysis on Project EDGE activities related to each topic
- **Key insights and implications:** Identifying key insights with implications for the future, collating issues for consideration by industry and indicating where further research is needed to inform decisions around specific topics.



CUSTOMER NEEDS AND EXPERIENCES

This chapter focuses on the research question:

How can integrating DER into the NEM be designed to enable simple customer experiences, deliver the needs of customers and improve social licence for active DER participation?

Overview

- VPP customers are the key to realising the full benefits from DER for all consumers through active coordination. This will require giving consumers incentives to join a VPP, with voluntary participation preferable to other mechanisms, as it gives consumers choice and voice regarding VPP participation, as well as helping to achieve social licence for active DER market participation.
- Consumer research conducted by Deakin University for Project EDGE found that consumer motivations for investing in DER and joining a VPP include financial benefits, energy independence and resilience, environmental benefits and 'peace of mind'. However, consumers are motivated primarily by a desire to reduce electricity bills and be energy self-reliant.
- Consumers are cautious about aggregators utilising their assets unless they trust that sufficient value is shared with them, and their personal utility is maintained. This creates challenges for aggregators because the desire to hold enough stored power was deemed most important by customers during periods of high demand for export, which typically coincide with high wholesale prices.
- Customers are open to increasing the amount of energy traded through a VPP provided it has been demonstrated they will be better off overall. This indicates an opportunity for customers to embrace more price-responsive models that provide an overall net benefit over a period of time.
- Customers may not need to see the distinct value of a joining a VPP if participation is offered as part of an attractive bundle of broader energy services. There are opportunities for aggregators to develop innovative business models that provide a 'multi-service' offering to customers.
- Interest in joining VPPs among broader electricity consumers is lukewarm and the value proposition remains unclear. Giving consumers an incentive to join a VPP will require developing and communicating compelling value propositions and building consumer trust.
- The DER export policy perceived as most fair by consumers involves no costly distribution network upgrades and includes the application of DOEs. Accordingly, policy makers should consider developing DER export polices that benefit all consumers – with and without DER – through reduced whole-of-system costs, as these may be perceived as fair by most consumers.
- Policy makers should explore standardised definitions, frameworks and processes for energy services and markets in which aggregators could participate, as this may assist aggregators to develop commercially viable and compelling incentives that promote greater customer participation and DER activation.
- Aggregators need to develop value propositions for joining a VPP that include financial and non-financial (such as environmental) benefits. They need to achieve social licence by building the trust consumers require to hand over control of their DER.

2.1 Context

Across Australia, DER are playing a critical and growing role in the transformation of the energy grid. In particular, Australian businesses and households have embraced rooftop PV at a much faster rate than other nations, and this trend is expected to continue. As growing numbers of passive DER – that is, DER that is not enabled to respond to external signals – impact operational demand and the secure operation of the power system, active coordination of DER will be increasingly important.

This will require shifting energy consumers from passive participants in the grid to active contributors, with VPP customers the key to realising the full benefits from DER through coordination. Successful coordination hinges, in part, on customers seeing value in joining a VPP and trusting that they will not be worse off.

DEFINITION
Virtual Power Plants (VPPs)

Virtual Power Plants (VPPs) are aggregations of small-scale DER, such as rooftop PV and storage, coordinated to deliver large-scale services for operators of the power system, distribution networks and electricity markets

DEFINITION
Customers and consumers

This report uses the term 'consumer' when referring to the broader population of electricity customers, regardless of whether they have active DER or not. 'Customer' is used when referring to consumers being recruited, or acquired, by an aggregator or retailer to participate in a VPP, or in the context of a consumer who forms a connection contract with a DNSP. The key element is the contractual relationship with a product and service provider.

The use of these terms in these contexts reflects that all customers are consumers – but not all consumers are VPP customers.

Australian consumers have already shown a willingness to invest in DER to reduce their reliance on the grid. Coordinating these resources effectively requires encouraging consumers to take a further step and join a VPP, through delivering sufficient financial incentives and identifying clear benefits for doing so. Voluntary participation is preferable to other mechanisms, as it gives consumers choice and voice regarding VPP participation. It also helps to achieve social licence for active DER participation.

In addition to voluntary participation incentives, market frameworks also need innovation around VPPs, so that products and services may be developed that benefit prospective customers, the VPP service provider and the power system.

2.2 Approach

Project EDGE sought to improve understanding of how consumers view participation in coordinated DER by engaging Deakin University to undertake comprehensive research into the motivations and perceptions of VPP customers and electricity consumers with no DER or VPP experience (i.e. potential aggregation customers).

This chapter synthesises key insights from Deakin's research to inform policy, regulatory reform and business decisions in relation to:

- Providing incentives for consumer participation in VPPs and accelerating the adoption of VPPs
- Building trust in aggregators managing their customers' DER
- Enhancing VPP customer satisfaction and retention
- Developing policies that fairly facilitate DER exports.

The insights can also inform industry in developing offers to build commercially viable service offerings that provide value to customers and whole-of-system needs.

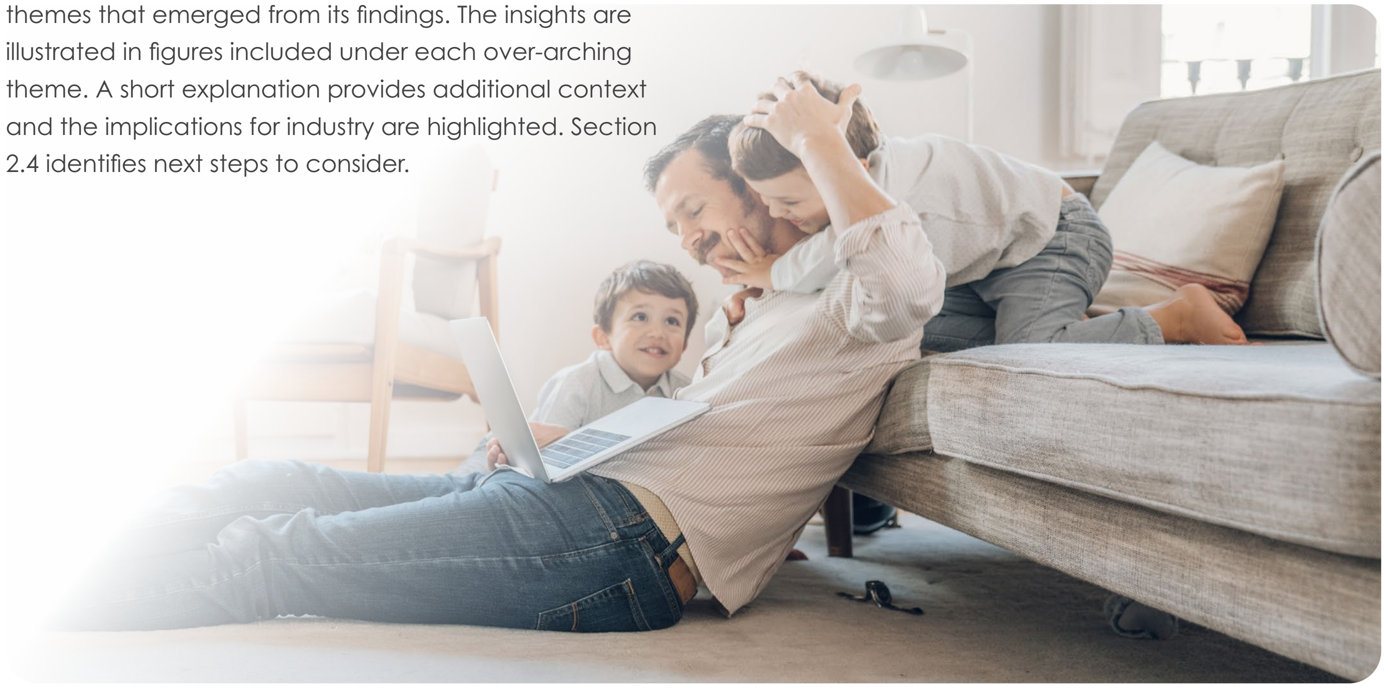
The insights should be read in the context of the research population sample. Deakin interviewed and surveyed customers of the three active aggregators participating in the Project EDGE field tests (i.e. Victorian customers). In terms of broader electricity consumer perceptions of DER and VPPs, Deakin surveyed consumers from the Australian states of New South Wales, Queensland, South Australia and Tasmania.

Given VPP participation in the NEM is nascent, aggregator customers interviewed by Deakin can be considered either innovators or early adopters, as they are within the first 2.5% (innovators) or next 13.5% (early adopters) of the general Australian population to have joined a VPP.[78]

Additionally, this context means the findings and insights from Deakin's research represent current perceptions and motivations and are not static. Therefore, while findings from Deakin's research on customers of the three EDGE aggregators can provide insights into customer perceptions in a nascent market, they should not be equated with consumer perceptions more broadly.

Comprehensive information about Deakin's full research for Project EDGE, including its methodology and detailed findings are published in several knowledge-sharing reports.[79] These publications present additional findings, details on the study design, the questions participants were asked and contextual considerations for some of the findings.

The following section gives an overview of key insights from Deakin's research across the main over-arching themes that emerged from its findings. The insights are illustrated in figures included under each over-arching theme. A short explanation provides additional context and the implications for industry are highlighted. Section 2.4 identifies next steps to consider.



2.3 Findings

This section summarises the key findings from Deakin University's customer research in Project EDGE.

2.3.1 Motivations for investing in DER and joining VPPs

Customers are facing increasing complexity and are influenced by a common set of motivating factors when deciding to join a VPP

Consumers are facing increasing complexity in their energy choices. A customer experience survey on navigating the energy transition, conducted across 18 global markets, with about 36,000 consumers, found that about half of consumers do not understand the energy actions and investments they can make to be more sustainable.[80] The complexities consumers are likely to face are illustrated in Figure 16

78 The five types of adopters for products and services are considered to be innovators, early adopters, the early majority, the late majority and laggards.
Rogers, E M. 1995, Diffusion of innovations. 4th Edition, the Free Press, New York.

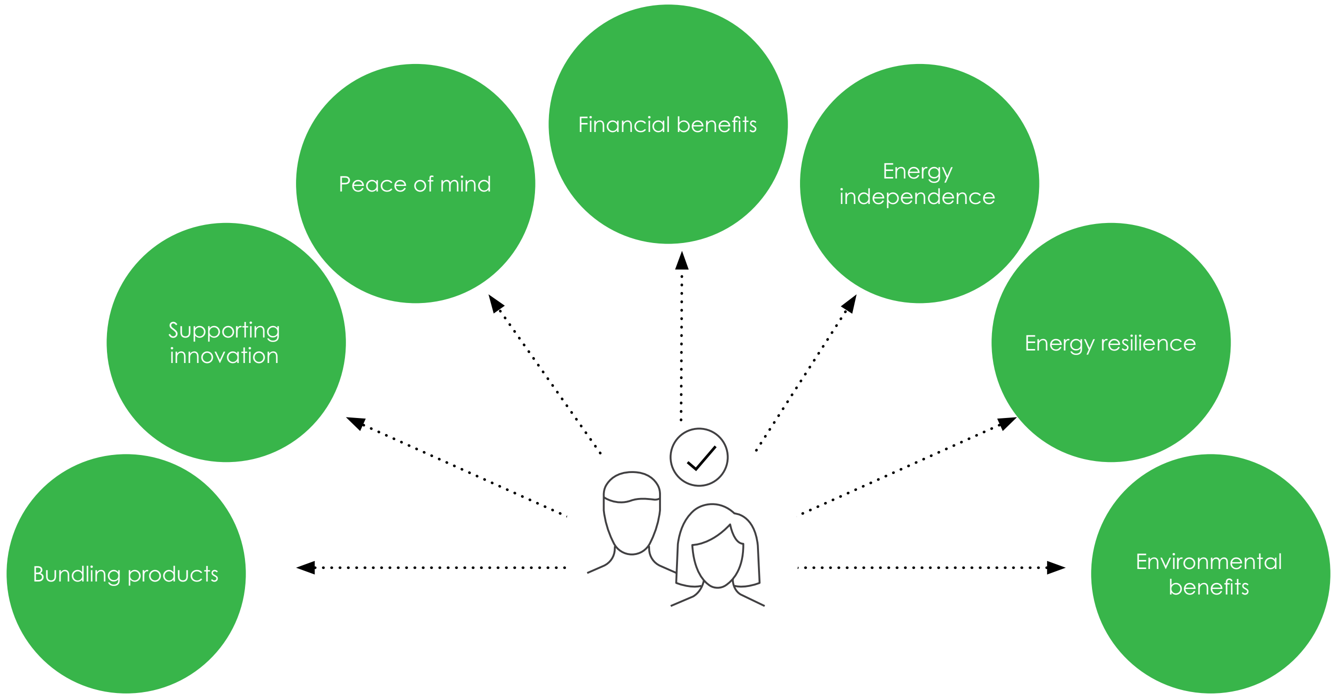
79 Project EDGE. 2022, Project EDGE: Public Customer Insight and Engagement Study Interim Report Version 1 June 2022. https://aemo.com.au/-/media/files/initiatives/der/2022/public-customer-insight-and-engagement-study-interim-report.pdf?la=en; Project EDGE. 2022, Project EDGE: Gaps in Existing DER Customer Insights Research Version 1 July 2022. https://aemo.com.au/-/media/files/initiatives/der/2022/project-edge-lit-review-der-customer-insights-research.pdf?la=en;
Project EDGE. 2022, Project EDGE: General Community Perceptions of Distributed Energy Resources. https://aemo.com.au/-/media/files/initiatives/der/2022/community-perceptions-of-der-and-aggregation-services.pdf?la=en;
Project EDGE. 2023, Project EDGE: Qualitative insights into the experiences of customers participating in a Virtual Power Plant field trial. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-qualitative-insights-for-customers-in-a-vpp.pdf?la=en

80 EY. 2022, As consumers lead the way, how can energy providers light the path? Navigating the Energy Transition Consumer Survey. https://www.ey.com/en_gl/power-utilities/how-energy-providers-can-light-the-path

Figure 16 | Complexities consumers may face in their energy choices

Deakin's consumer research identified a common set of motivations for investing in DER.[81] Through semi-structured interviews conducted with customers of the three aggregators participating in the Project EDGE field trials (Discover, Mondo and Rheem), Deakin identified key motivating factors for adopting DER and joining a VPP. These are illustrated in Figure 17.

Figure 17 | Motivating factors for consumers adopting DER and joining a VPP



81 Project EDGE. 2023, Project EDGE: Qualitative insights into the experiences of customers participating in a Virtual Power Plant field trial. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-qualitative-insights-for-customers-in-a-vpp.pdf?la=en

Deakin found motivations were multi-faceted and some customers blurred the benefits of DER and VPPs. This may create challenges with helping customers understand the relative benefits of adopting DER compared to joining a VPP. It may also create challenges with managing customer expectations if issues with one are misattributed to the other.

Customers also recognised the environmental benefits of adopting DER and joining a VPP. For some of these customers, a key benefit identified was the ability of DER and VPP adoption at scale to facilitate carbon emissions reduction. However, attainment of these outcomes was less valued by consumers relative to having a reliable supply of power, saving money and receiving good service.[82]

Deakin triangulated its findings with other Australian DER and Project EDGE research, confirming that a relatively common set of perceptions, such as financial returns and environmental drivers, underpin decisions to adopt DER and join a VPP regardless of the aggregator or customer cohort being researched.[83]

Findings from the cost benefit analysis (CBA) conducted for Project EDGE support environmental drivers for participation. The CBA found greater uptake and participation of active DER in markets can reduce CO2e[84] by displacing technology types with greater emissions intensity.[85] Even though environmental factors may not be the most significant driver for all consumers, it is nonetheless a motivating factor and, as such, plays a role in developing social licence for VPPs.[86] Chapter 3 provides details on the CBA's findings on the total emissions and cost avoided through greater DER uptake and integration.

INSIGHTS

Influencing factors for customer investment in DER and VPP participation

Deakin's research on customers of the three active aggregators participating in Project EDGE found there are multiple factors that influence customers' willingness to invest in DER and join a VPP. Aggregators and industry will need to develop a variety of narratives and compelling business offers with multi-faceted benefits (e.g. financial and environmental) to encourage greater participation in VPPs. Participation in VPPs would also be facilitated consumers having access to readily available and easy to understand information about the benefits of a VPP, as distinct from the benefits of solely investing in DER.

Customers are motivated primarily by a desire to reduce electricity bills and be energy self-reliant

Financial benefits were often identified as a motivating factor for adopting DER or joining a VPP. Customers also understood that by participating in a VPP, they could benefit from variable pricing in the energy market; for example, by exporting stored power during periods of low supply and high demand.

However, as discussed previously, these insights are from customers who can be considered innovators or early adopters. The views of customers who do not already have DER or who do not have experience with VPPs, and non-innovators and late adopters, may be different. Given this is a nascent market, customers with less experience are likely to need more information about the benefits of price--responsiveness, rather than assuming they understand these benefits.

82 Project EDGE. 2022, Project EDGE: General Community Perceptions of Distributed Energy Resources, p 18. https://aemo.com.au/-/media/files/initiatives/der/2022/community-perceptions-of-der-and-aggregation-services.pdf?la=en;

83 Project EDGE. 2023, Project EDGE: Qualitative insights into the experiences of customers participating in a Virtual Power Plant field trial, p 19. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-qualitative-insights-for-customers-in-a-vpp.pdf?la=en

84 CO2e is a measure used to compare the emissions from various greenhouse gases on the basis of their global warming potential, by comparing amounts of other gases to the equivalent amount of carbon dioxide with the same global warming potential.

85 Deloitte Access Economics. 2023, Project EDGE CBA Final Report, p 57. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

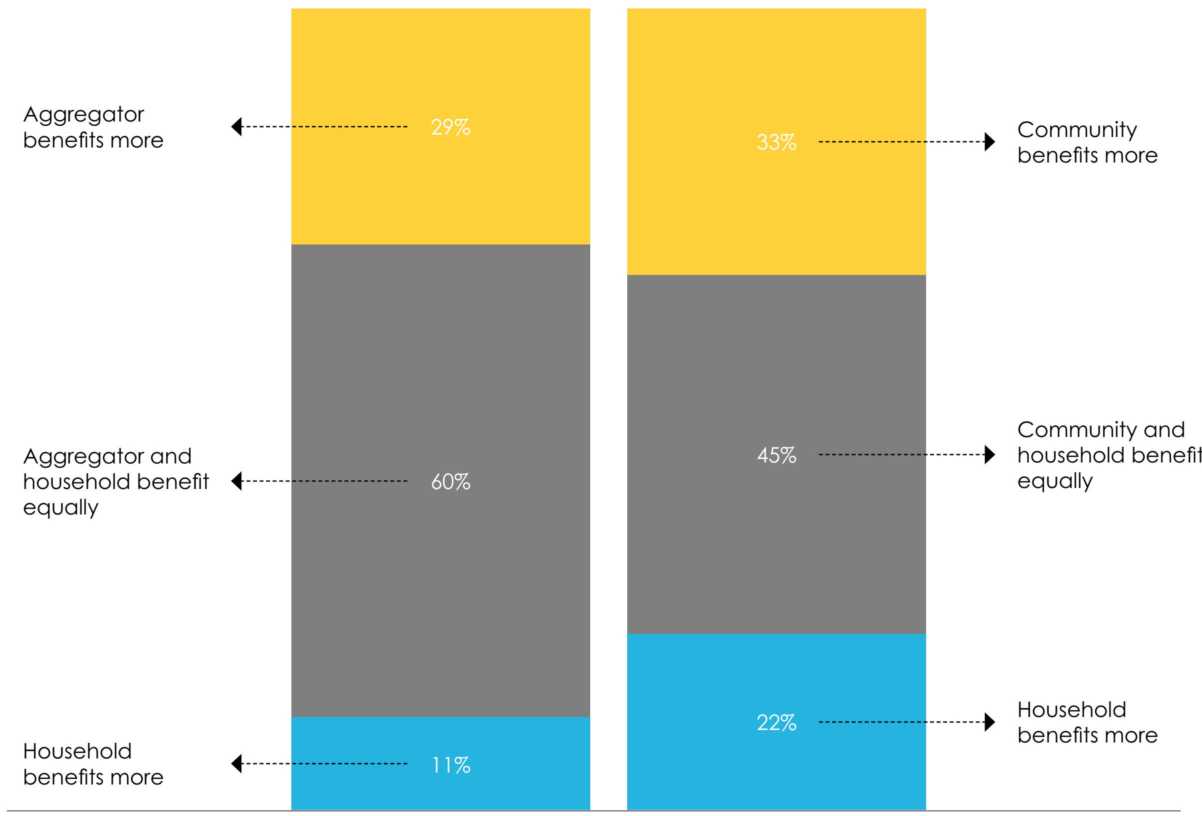
86 Project EDGE. 2022, Project EDGE: General Community Perceptions of Distributed Energy Resources, p 18. https://aemo.com.au/-/media/files/initiatives/der/2022/community-perceptions-of-der-and-aggregation-services.pdf?la=en;

Insufficient financial returns were a persistent concern for customers.[87] This suggests that aggregators managing their customers' financial expectations will be important for acquiring and retaining customers. This also indicates an element of reputational risk for aggregators: if aggregators do not manage customers' financial expectations adequately or provide sufficient value to customers, it could result in customer churn and negative customer experiences that create negative perceptions of that aggregator.

Figure 18 shows the perceived distribution of benefits between households and aggregators and households and the wider community. Sixty per cent of respondents perceived aggregators and households benefitted equally. Meanwhile, 11% of customers believed households benefitted more than aggregators and 22% of respondents perceived households to benefit more than the community.

Nonetheless, 29% of customers believed aggregators benefitted more from VPP participation than households. While this is not the majority, it does represent a significant proportion of customers interviewed.

Figure 18 | Customer perception on who benefits more from VPP participation, comparing households and aggregators and households and the community



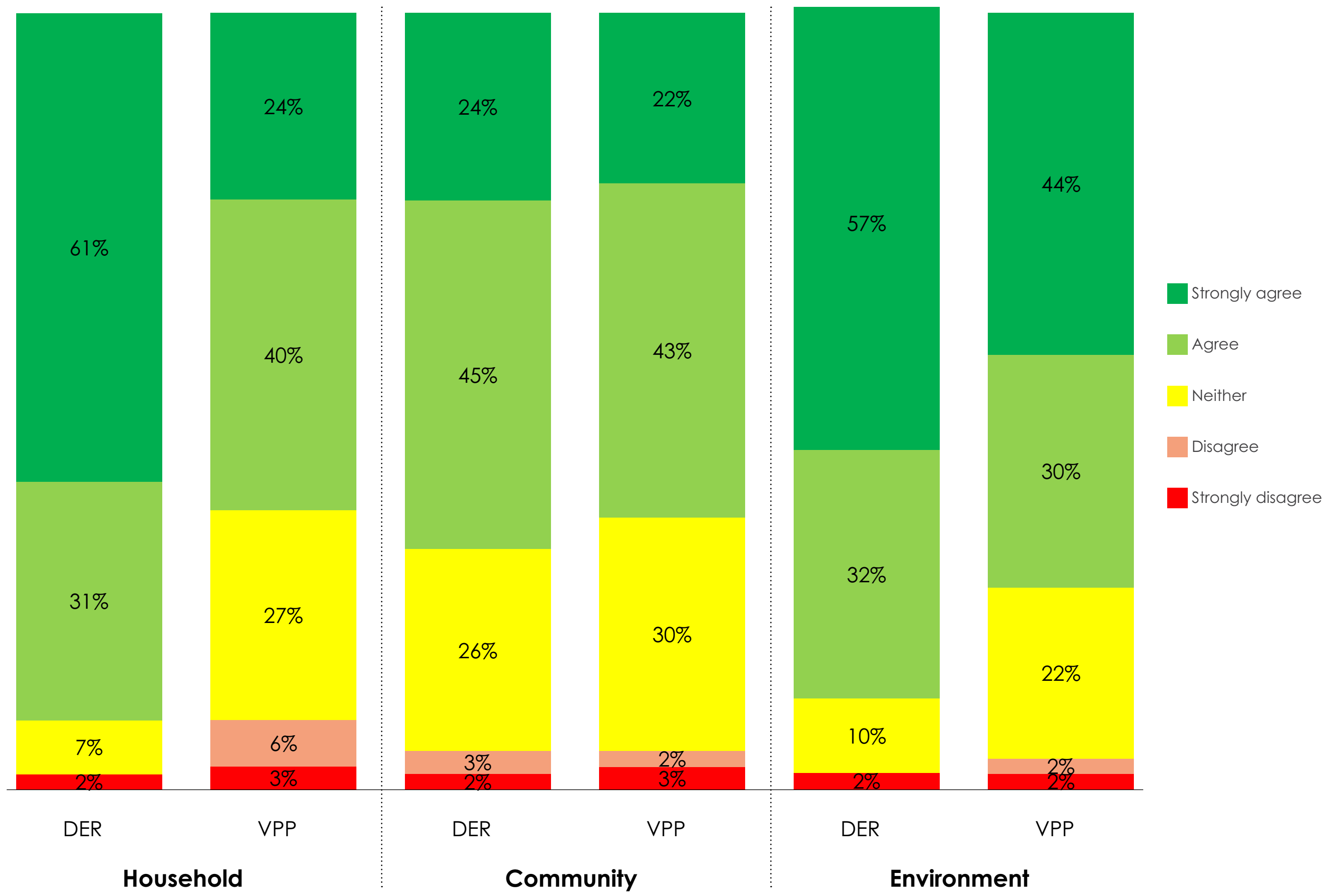
Source: Project EDGE, Customer Insights Study Summary Report[88]

These findings suggest that industry needs to develop a stronger case to encourage greater participation in VPPs. In particular, aggregators will need to ensure offers are simple to understand and provide transparency of benefits, so customers do not perceive aggregators as 'profit-taking' and create detrimental sentiments of distrust. Deakin notes that accelerating VPP adoption will likely require a greater proportion of customers perceiving they are benefitting more than aggregators.

Figure 19 shows customer's perceptions regarding who benefits from DER and VPP adoption; specifically, the extent to which households, the community and the environment are seen to benefit.

Sixty-one per cent of customers strongly agreed that adopting DER had benefitted their household, while 24% shared that opinion with regard to joining the VPP.

Figure 19 | Customer perceptions on who benefits from DER and VPP adoption



Source: Project EDGE, Customer Insights Study Summary Report[89]

87 Project EDGE. 2023. Project EDGE: Qualitative insights into the experiences of customers participating in a Virtual Power Plant field trial, p 3. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-qualitative-insights-for-customers-in-a-vpp.pdf?la=en

88 Project EDGE. 2023. Project EDGE: Customer Insights Study Summary Report, p.18. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge---customer-insights-study-summary-report.pdf?la=en

89 Project EDGE. 2023. Project EDGE: Customer Insights Study Summary Report, p.18. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge---customer-insights-study-summary-report.pdf?la=en

In terms of satisfaction with financial rewards, 71% of customers were somewhat or very satisfied with the financial rewards received for participating in the VPP. Meanwhile, 30% were unsure what financial impact their VPP participation had on their energy bills. Overall, these findings suggest the value proposition for joining a VPP requires strengthening.

Energy independence and energy self-sufficiency was another motivating factor. This was also linked to financial considerations. Deakin found the desire for energy independence was often grounded in a deeper concern about minimising future financial uncertainty or pains. Customers generally considered that as long as enough power remained to cover their energy needs, they appreciated the ability to gain additional financial benefits by participating in VPPs.

This aligns with the market participation behaviour adopted by the three aggregators participating in the field trials. They developed their business models around 'optimising self-sufficiency' based on what they understood their customers' preferences to be.

This also suggests that as DER installations get bigger, with more storage capacity (e.g. bigger batteries for the same cost, or vehicle-to-grid capable EVs with larger battery capacities), customers may be more willing to participate in VPPs using spare capacity in their DER after their personal needs are met.

INSIGHTS

Financial benefit is a key driver for customer decisions to join a VPP

While customer decisions to join a VPP are multi-faceted and cannot be attributed to a single factor, a key driver is financial benefit. As such, aggregators that provide offers with easy-to-understand financial benefits, alongside other tangible or compelling benefits (e.g. environmental) should have stronger success in acquiring customers to participate.

2.3.2 Motivating additional coordinated DER activity

Social licence and simple offers are required to support more price-responsive models

Consumers in the general community are cautious about aggregators utilising their assets unless they trust that sufficient value is shared with them, and their personal utility is maintained. Only 24% of customers in Deakin's research on general community perceptions of DER said they trusted aggregators to use their assets.[90]

Many customers of the participating aggregators would only agree to an increase in exporting activity to the grid if they could be assured that enough stored power remained in their batteries to meet their self-consumption needs. This sentiment creates additional challenges for aggregators because the desire for enough stored power being available for self-consumption was deemed most important by customers during periods of high demand for export that typically coincide with high wholesale prices.

To encourage additional trading activity through VPPs, aggregators will need to clearly explain to customers the potential benefits of being price-responsive and the implications for their energy use.

This approach is reflected in the model adopted by AGL.[91] AGL commits to customers that coordination of their DER devices will not impact the customer's electricity bill and the customer will be net financially positive in an AGL VPP program.[92] A simple translation to dollars over a year, and an assurance the customer will be better off overall, could be a potential strategy to move towards more price-responsive business models.

90 Project EDGE. 2022, Project EDGE: General Community Perceptions of Distributed Energy Resources, p 38. https://aemo.com.au/-/media/files/initiatives/der/2022/community-perceptions-of-der-and-aggregation-services.pdf?la=en

91 Discussions with AGL covered a variety of topics, including customer acquisition approaches. The insights discussed in this paper are high-level to maintain the commercial-in-confidence nature of these discussions.

92 AGL pays their customers in several different up-front ways, depending on whether the system was already installed or if AGL is managing the installation. In addition to an up-front payment, AGL ensures that VPP activities don't cause bill impacts that erase the customer's revenue gained from the VPP. Bill impact is defined as a deviation from the solar self-consumption baseline. AGL notes that is not always straightforward to calculate, but something AGL has invested in to make VPP products that protect the important, primary customer value stream. Once AGL gets close to a bill impact threshold, it withdraws the DER assets from the market services. This approach ensures the customer will be net financially positive in an AGL VPP program.

INSIGHTS

The 'better off overall test'

Customers were open to increasing the amount of energy traded through a VPP as long as it passed a 'better off overall test'. Customers wanted assurances they would ultimately come out ahead from any additional trading activity. This indicates there is opportunity for customers to embrace more price-responsive models that provide an overall net benefit over a period of time.

INSIGHTS

Easy to understand information about DER device usage should be readily available

There is a balance between how much customers want to know and the level of automation in the process of participation. The key insight is that easy to understand information about how and when their devices are being used is readily available for those customers that want digestible detail.

Another potential approach from Deakin's analysis is the use of personalised messages highlighting the amount of under-utilised stored energy the customer has and where an opportunity exists to export the energy through the VPP.[93]

Overall, strategies associated with more price-responsive business models will need to clearly and transparently outline the benefits of increased export to the grid, especially in comparison to self-consumption. Customers want to see and understand the impacts of their activities.

However, most customers preferred VPP activities to be automated. The reason for this is that the value proposition for actively managing how or when VPP activity takes place was not perceived to justify the learning curve required to undertake customisation. As a result, for many customers, this preference for automation meant that the VPP remained a 'black box'.

Equal partnerships are important to customers

Customers all wanted to be treated as equal partners by aggregators. This is because of the value customers recognise they are providing to aggregators through use of their DER assets. Customers saw financial reward as one way to form a more equal partnership. However, non-financial incentives such as aggregators providing ongoing maintenance of DER assets was another suggestion made by customers. Some customers were concerned that increased exporting activity could detrimentally affect the lifetime of their DER devices.

This suggestion aligns with the fact that frequent use of DER devices has an operational impact on the lifetime and performance of the asset. Aggregators could test offering maintenance of the assets as 'compensation' for their use.

Bundled services may be attractive

Another key finding from Deakin's work is that customers may not need to see the distinct value of a joining a VPP if participation is offered as part of an attractive bundle of broader energy services.[94] This creates opportunities for aggregators to develop innovative business models to provide a 'multi-service' offering to customers.

This approach can simplify the customer experience and create positive sentiments toward VPPs and the value of participating in markets. However, it also means care is needed so that a negative experience with one non-VPP element of the bundle does not result in negative sentiments towards participation in VPPs.

93 Project EDGE. 2023, Project EDGE: Qualitative insights into the experiences of customers participating in a Virtual Power Plant field trial, p 4. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-qualitative-insights-for-customers-in-a-vpp.pdf?la=en

94 Project EDGE. 2023, Project EDGE: Qualitative insights into the experiences of customers participating in a Virtual Power Plant field trial, p 3. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-qualitative-insights-for-customers-in-a-vpp.pdf?la=en

2.3.3 **Giving consumers an incentive to participate in VPPs**

It is the role of service providers to manage complexity for customers and offer simple, transparent solutions and value

Deakin found that for some customers, participating in a VPP was a 'leap of faith' that due diligence activities, such as seeking information from independent third parties, could not fully overcome. For example, some customers could not determine the net financial implications of participating in a VPP until after they had joined, if at all. This indicates that aggregators, and more broadly market bodies, should make easy to understand information about the various benefits of participating in VPPs, including the financial benefits, widely available.

Customers expected aggregators to simplify the entire onboarding and participation process; for example, by coordinating the various parties required to complete the installation of the devices enabling VPP participation and keeping them informed of the process. Deakin also found that some customers had heightened or unrealistic expectations about what DER or VPPs could achieve. This indicates aggregators will need to manage a variety of expectations, not just financial, that align with the experiences of participating in VPPs to further build trust and retain customers.

As noted earlier, for some customers, participation in a VPP was motivated by a broader bundle of products and services being offered by the aggregator, of which the VPP was one element. For these customers, an integrated energy setup, with different energy sources and technologies managed as a single integrated energy offering, was the primary attraction. Many consumers are not interested in having an in-depth understanding of energy technologies. For such consumers, energy is simply a means to unlock the use of their home appliances and devices. This means there is an opportunity for aggregators to develop unified solutions that enable customers to benefit from bundled, integrated energy offerings. This presents a possible alternative strategy to drive participation in VPPs.

Customers also want plain language and engaging information that is not unnecessarily technical. Some customers had challenges understanding the financial information they were presented, such as the rates charged for importing or exporting energy. This indicates the importance of providing customers with personalised analytics to help them contextualise the financial impact of joining a VPP for their household. It also indicates greater VPP participation could be facilitated by reducing the complexity of information provided to consumers and giving them trusted tools to better estimate the financial implications and benefits.

INSIGHTS
Facilitators of mass participation in VPPs

Mass participation in VPPs may be facilitated as:

- VPPs build trustworthy track records (social licence) in operating DER to deliver value to customers.
- Customer models to sign up to, and participate in, a VPP are simplified.
- Personalised information about the benefits (financial and non-financial) of joining a VPP are communicated in easy to understand language.
- DER cost reductions, or VPPs delivering more electricity services as they scale, make the financial case for VPP participation more compelling.

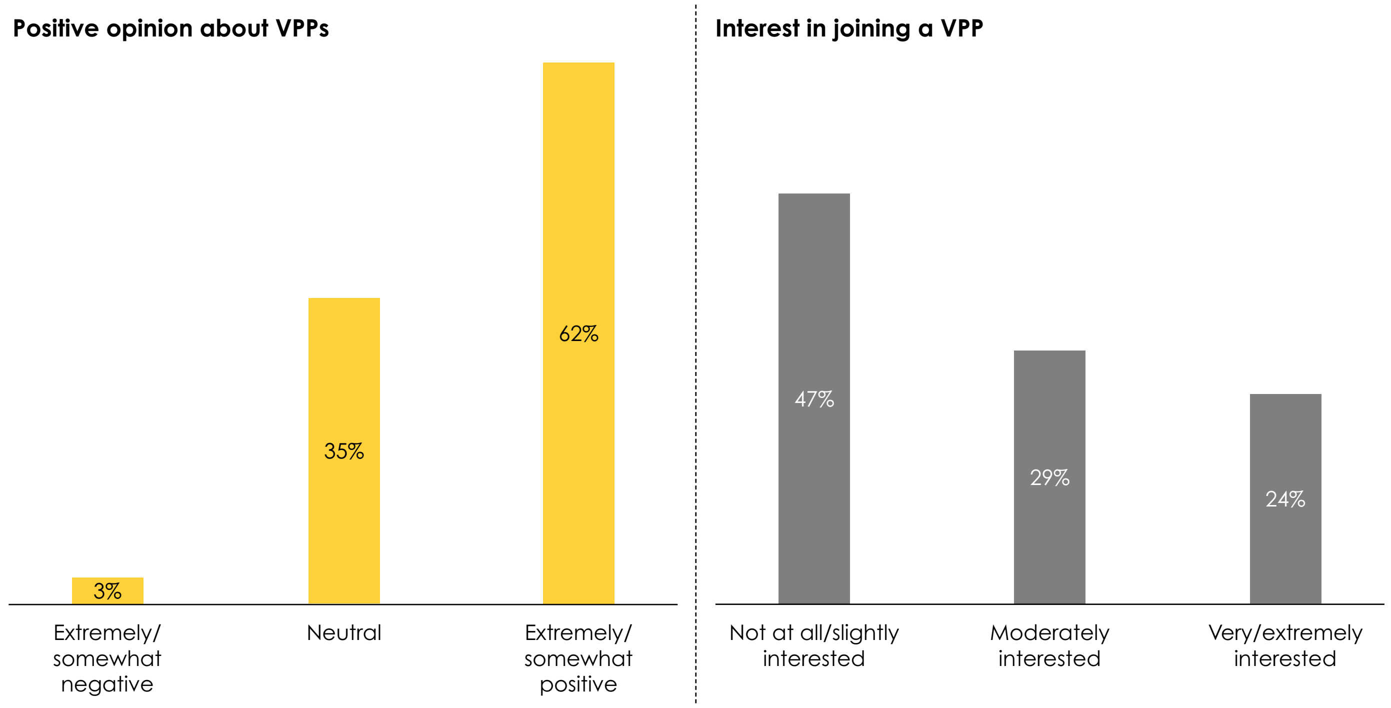
2.3.4 **Perceptions of DER and VPPs, and their value**

Interest in joining VPPs among broader electricity consumers is lukewarm and the value proposition remains unclear

Deakin conducted research to understand perceptions on investing in DER and joining VPPs among the general community (i.e. broader electricity consumers who were not participating in Project EDGE and some of whom had no direct experience with DER).[95] Deakin found that broader consumer interest in joining a VPP was lukewarm.

Figure 20 shows 62% of consumers were positive about VPPs after being presented with a summary about them. However, as Figure 20 also shows, this positive perception did not translate automatically into an interest in joining a VPP.

Figure 20 | Consumer perceptions about VPPs and interest in joining a VPP



Source: Project EDGE, Customer Insights Study Summary Report[96]

Accordingly, Deakin noted that this finding suggests additional work is required to demonstrate the value of adopting DER and participating in VPPs for the late majority and laggards consumer categories (those consumers who are likely to be late – or among the last – to adopt an innovation or technology).

Nonetheless, half of respondents were interested in joining a VPP, with almost a quarter extremely interested. Additionally, only a small number (3%) had extremely or somewhat negative opinions about VPPs.

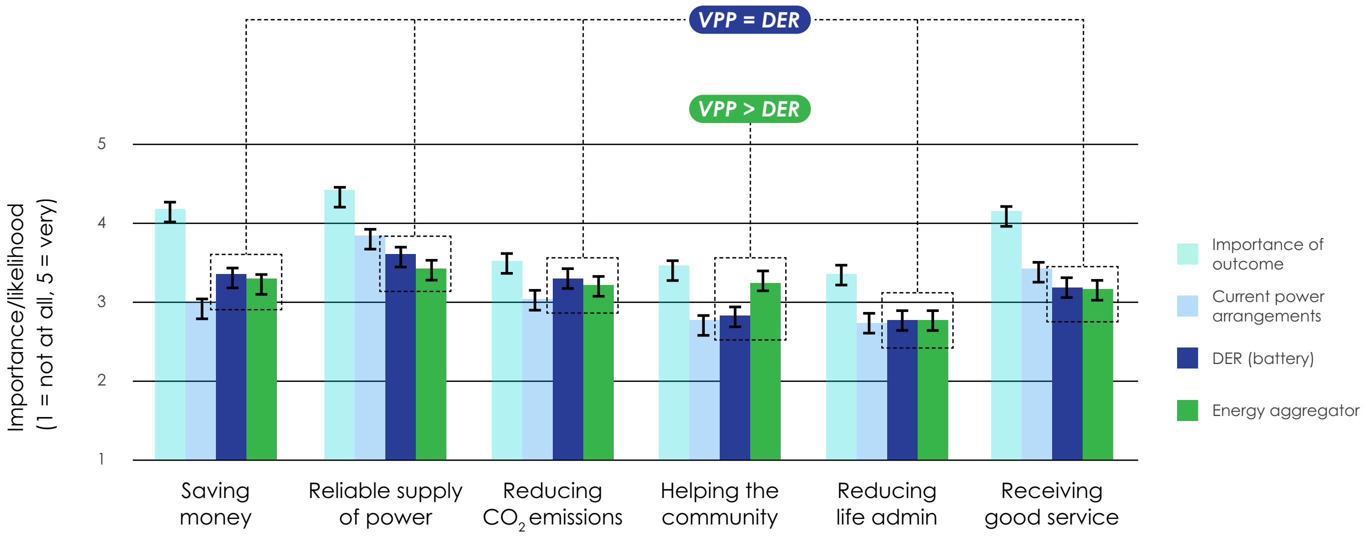
This indicates that as DER increases and more consumers have access to clear information on the potential benefits of joining VPPs, positive opinions about VPPs may translate into interest in joining VPPs. This could be facilitated by access to easy-to-understand information from trusted sources about the direct benefits and indirect benefits (e.g. reduced electricity bills for all consumers through whole-of-system benefits – see Chapter 3) to consumers of joining a VPP.

95 Project EDGE. 2022, Project EDGE: General Community Perceptions of Distributed Energy Resources. https://aemo.com.au/-/media/files/initiatives/der/2022/community-perceptions-of-der-and-aggregation-services.pdf?la=en

96 Project EDGE. 2023, Project EDGE: Customer Insights Study Summary Report, p.6. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge---customer-insights-study-summary-report.pdf?la=en

Figure 21 shows the rated importance and expectation of outcomes (benefits) presented to consumers from a scale of 1 (not at all important or likely) to 5 (very important or likely). Out of the six outcomes presented to consumers, all but one (helping the community) were rated the same under a VPP compared with simply adopting DER.

Figure 21 | Perceived benefit in joining a VPP compared to adopting DER



Source: Project EDGE, Customer Insights Study Summary Report[97]

These findings show that consumers perceived joining a VPP would deliver equivalent outcomes to adopting DER. Since adoption of DER is required to join a VPP, Deakin noted this finding suggests these consumers saw little incremental benefit in joining a VPP over and above adopting DER.

One exception was 'helping the community'. Consumers saw this outcome as being more likely if they joined a VPP compared with simply adopting DER. However, helping the community was not one of the three outcomes that consumers were most interested in achieving. These findings suggest that for many consumers, the value proposition for joining a VPP is unclear.

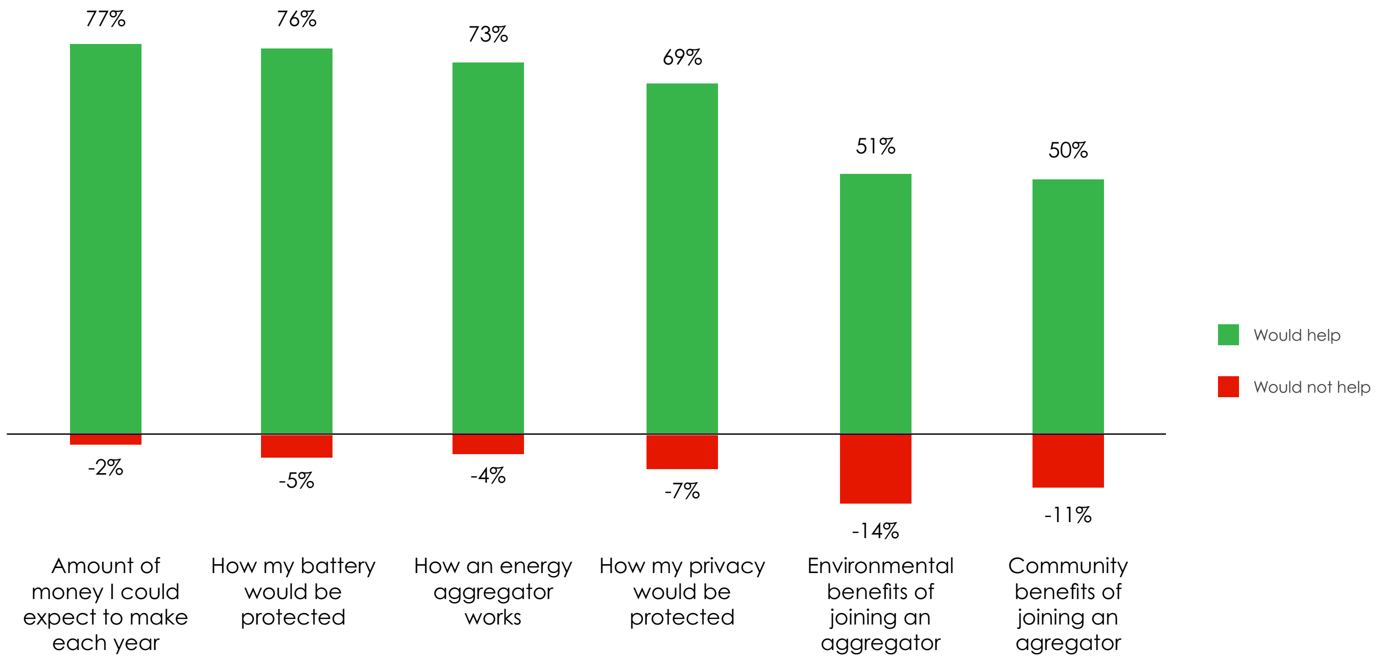
As discussed in 5.3.1, VPP participation can provide value opportunities for DER customers beyond owning DER and utilising it for self-consumption only. As such, findings that show consumers perceive joining a VPP and adopting DER as providing equivalent outcomes indicate more work is needed to inform consumers about the benefits of joining a VPP.

Trust was another common theme among consumers and customers in Deakin's research. Most consumers surveyed reserved judgement on whether aggregators could be trusted to access and export power on their behalf. Sixty-one percent were unsure, while 15% perceived aggregators could not be trusted. Consumers valued reassurance that aggregators would deliver the value promised.

Consumers identified information about financial benefits, consumer safeguards and information about how a VPP works as factors that would help them decide to join a VPP. Figure 22 shows the proportion of consumers who think a given type of information would, or would not, help them decide to join a VPP. Most consumers (77%) desired information about the likely financial returns they would receive.

97 Project EDGE. 2023, Project EDGE: Customer Insights Study Summary Report, p.8. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge---customer-insights-study-summary-report.pdf?la=en

Figure 22 | Type of information that would help consumers decide to join a VPP



Source: Project EDGE, Customer Insights Study Summary Report[98]

Consumers also valued transparency and simplicity in the business models and service offerings provided by VPPs. Consumers indicated they would be willing to let aggregators use their DER if offers are presented to them simply (easy to understand) and provide sufficient value over time.

INSIGHTS

Strategies to help consumer sentiments on joining a VPP

Deakin's research on broader electricity consumer sentiments on joining a VPP suggests strategies to provide consumers with reassurance and transparency in relation to how and when their devices are controlled, and guaranteed earnings, will be important to build trust among the early majority.

Increasing readily available information could help the early majority category of consumers decide whether to join a VPP. Take up by these consumers (who comprise a sizeable proportion of the general population) is likely to lead to much wider participation in VPPs.

Additional work is required to enhance the value proposition of joining a VPP. Unless a compelling value proposition is clearly and simply communicated, residential consumers are unlikely to perceive a benefit from joining and participating in a VPP.

98 Project EDGE. 2023, Project EDGE: Customer Insights Study Summary Report, p.9. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge---customer-insights-study-summary-report.pdf?la=en

2.3.5 **Barriers to joining VPPs**

There are some key potential barriers that could affect VPP participation

Deakin's interviews with customers of the three participating aggregators identified three key potential barriers that could affect the motivations of other consumer cohorts to joining a VPP. These are:

- Unfair financial returns.
- Insufficient stored energy to cover self-consumption needs.
- Data security.

In terms of financial returns, customer perspectives were focused on feed-in-tariffs from exporting energy to the grid from their rooftop PV rather than the financial returns from participating in a VPP. This creates a risk that customers conflate their negative sentiments about perceived unfair feed-in-tariffs with participation in a VPP.

This indicates that to encourage active participation in VPPs, clear and simple information on the distinction between passive DER compared to active DER via a VPP should be readily available. It also means that aggregators need to clearly delineate the benefits and financial returns for which they are responsible, compared to those set by different or upstream industry actors.

Regarding self-consumption, customers understood that by giving control of their DER to an aggregator, they would not always be able to use their own stored power to meet their energy needs. This was seen as a barrier for some customers averse to buying electricity from the grid when they could be using their own generated and stored power.

This emphasises the need for aggregators to develop models that clearly communicate an overall net benefit for the customer, even though they may not be able to use DER for self-consumption at all times.

The industry will also need to develop consumer trust, along with robust frameworks, to mitigate consumer concerns regarding data security.

DER interoperability barriers

Interviews with aggregators outside of the Deakin University research identified DER interoperability barriers can limit the ability for aggregators to integrate with customers' DER to deliver services. There is a need for DER interoperability measures to not just cover physical performance standards, and communications protocols but also extend to common data/information models and requirements for local control interfaces to be made available for aggregators that have explicit consent to operate their DER.

This will enable aggregators to more easily integrate different DER into their portfolios, and enable customers to invest in DER knowing that multiple service providers can operate their DER, which increases customer choice.

2.3.6 **Approaches to help aggregators deliver value to customers**

Simplifying aggregator experiences to deliver services across the NEM would make it easier to create simple offers for customers

'Simplifying the aggregator experience' refers to removing complexity (to the extent possible) related to the role and experience of aggregators in coordinating DER and delivering various electricity services. It means simplifying the functions, processes and interactions for aggregators to reduce their operating costs and facilitate their access to revenue opportunities in electricity markets and off-market (business to business).

Discussions with the aggregators participating in Project EDGE highlighted that developing the capabilities needed to participate in energy markets and develop high value business models (see section 5.3.2) would require significant investment and incur ongoing operational costs.

To facilitate a nascent market, existing electricity market frameworks, such as central scheduling and dispatch, will need to be adapted to be fit-for-purpose for DER. Greater complexity in delivering electricity services leads to higher costs for aggregators to set-up the required systems, processes and capabilities.

Standardising many elements of the value chain for aggregators to deliver multiple electricity services (e.g. DOEs, data exchange, local services delivery) can reduce aggregators' costs, enabling more value to be shared with customers, which – in turn – could lead to higher VPP participation.

2.3.7 **Considerations for aggregators to access additional revenue streams**

Delivering multiple services can result in aggregator platform cost efficiencies via economies of scale

Discussions with all four aggregators (the three participating in the field tests and AGL) noted that investing in the systems and processes required to participate would be costly. However, once the foundation blocks are established, the costs to enhance these systems and processes to enable participation in other markets would be incremental.

Accordingly, access to additional revenue streams early in VPP development has the potential to provide a greater return on investment for aggregators. These insights from participating aggregators suggest that minimising complexity in processes enables greater participation and provision of value.

The potential technical and service progressions aggregators could consider with regard to delivering multiple services and accessing additional revenue streams are discussed in sections 5.3.2 and 5.3.3.

2.3.8 **Consumer perceptions of DER export policy**

Consumers consider the personal costs and benefits of DER export policies when assessing the fairness of those policies

To understand consumer perceptions on fair DER export policy, Deakin presented consumers with four policy scenarios:

- *Scenario 1:* The capacity of the smaller pipes is not increased, so there are no upgrade costs. This means that as more households install solar panels, pipe capacity is reached more quickly, limiting the amount of power households can export and increasing the price of power for everyone.
- *Scenario 2:* The capacity of the smaller pipes is not increased, so there are no upgrade costs. Instead, households are allowed to export more than they currently can when demand for power is high, but less than they currently can once the pipes come close to capacity.
- *Scenario 3:* The capacity of the smaller pipes is increased so that more households can export more power. The cost of these upgrades is shared by all households (including those without solar panels or batteries).
- *Scenario 4:* The capacity of the smaller pipes is increased so that more households can export more power. The cost of these upgrades is covered by export charges, which are only applied to households that export power to the grid.

To help consumers understand the scenarios, they were provided with a metaphor equating transmission lines to big pipes and distribution lines to small pipes. The metaphor stressed that grid safety and stability depended on pipe capacity not being exceeded.

Consumers with rooftop PV perceived the cost of upgrading pipe capacity being borne by all consumers (scenario 3) was fairer than those without rooftop PV. Consumers without rooftop PV perceived the cost of upgrading pipes borne by consumers with exporting DER (scenario 4) was fairer than those with rooftop PV. The scenario reflecting the application of DOEs and no pipe upgrades (scenario 2) was perceived with equivalent fairness across consumers with and without rooftop PV.

Deakin found that consumers perceive 'fair' policy as one that delivers the greatest benefits to their own household. Consumers consider the personal costs and benefits of DER export policies when assessing the fairness of those policies. Ultimately, consumers want fairness applied to their own circumstances.

However, the DER export policies deemed most fair in Deakin's research, regardless of rooftop PV ownership status, included the application of DOEs (which benefits consumers with rooftop PV) and involved no costly distribution network upgrades, which benefits all consumers. This indicates that a policy that provides whole-of-system value and reduced costs may be perceived as 'fair' by most consumers, as all households will benefit.

The challenge for industry and policy makers will be to ensure the narrative around DER export policies removes technical complexities and industry jargon and makes the benefits for all households – with or without rooftop PV – clear and easy to understand.

2.4 **Key insights and implications for industry**

Deakin's consumer research indicates that developing value propositions with tangible financial benefits and building consumer trust can encourage consumer participation in VPPs. Project EDGE notes the following key insights and implications for industry.

For policy makers

- Prioritise reforms that enable customers, and the service providers they nominate, to have simple access to real-time data for their DER.
- Prioritise DER interoperability reforms that simplify how aggregators integrate new DER into their portfolios to simplify customer switching and enable customer choice.
- Recognise that social licence is a key challenge for industry and that, if integrating DER into electricity markets at scale is to provide net benefits to all consumers, social licence needs to be developed to prove that customers can trust aggregators to utilise their DER devices in a way that supports system needs but also provides net value to the customer.
- Consider strategies to support the development of DER social licence and collaborate with consumer advocacy groups, market bodies and industry to identify the information and mechanisms that could facilitate the building of DER social licence.
- Consider developing DER export policies that benefit all consumers – with and without DER – through reduced whole-of-system costs, as these may be perceived as fair by most consumers.
- Explore and introduce consistent definitions, frameworks and processes for energy services and markets in which aggregators could participate, as this may assist aggregators to develop commercially viable and compelling incentives that promote greater customer participation and DER activation.
- When designing electrification incentives, consider that higher DER volumes responding to energy price signals via VPPs can reduce CO_2e by displacing technologies with greater emissions intensity.

For aggregators

- Simplify customer models to sign up to and participate in VPPs and consider how VPP participation can be packaged as part of broader product bundles for customers.
- Communicate how customers will be 'better off overall' by joining a VPP.
- Consider how to build on three key elements to develop commercially viable business models that support power system needs and provide tangible benefits to all consumers:
  1. *Value proposition:* The value proposition for joining a VPP should include, and clearly communicate before and after sign-up, tangible financial and non-financial benefits of participation.
  2. *Motivating a move beyond self-consumption:* Customers are not averse to increasing the amount of power they export through a VPP provided it has been demonstrated they will be better off overall.
  3. *Social licence:* Transparent communication with readily accessible and easy to understand information can facilitate building the trust consumers need to allow aggregators to utilise their DER.
- Recognise that building a consistent track record of using customer assets while ensuring they are financially 'better off overall' and that their DER is available for customers to use as and when expected will help to build trust.

COST BENEFIT ANALYSIS AND ALIGNMENT TO THE NATIONAL ELECTRICITY OBJECTIVE

This chapter focuses on the research question:

Does the DER marketplace promote efficient investment in, and efficient operation and use of, electricity services for the long-term interest of consumers?

Overview
• The CBA conducted by Deloitte Access Economics and Energeia for Project EDGE identified that all consumers stand to benefit from accelerated and optimised integration of active DER in the NEM.
• An incremental benefit is shown across all CBA scenarios in comparison to the base cases over the 20-year time horizon examined. The CBA found that greater coordination of active DER in the NEM can result in an incremental benefit of up to \$5.15b under the AEMO ISP step change DER uptake assumptions and up to \$6.04b under the high DER uptake assumptions.
• The Project EDGE arrangement of roles and market configurations was found to avoid 15.1TWh of customer rooftop solar curtailment to 2030 and up to 90.6TWh across the 20 year time horizon to 2042 under the AEMO ISP step change DER uptake assumptions and avoid 50.1TWh of customer rooftop solar curtailment to 2030 and up to 257.1TWh across the 20 year time horizon to 2042 under the high DER uptake assumptions.
• Across the 20-year time horizon total emissions avoided can be up to 18,859,157 tCO_2e (\$1.54b) under the AEMO ISP step change DER uptake assumptions and up to 32,871,522 tCO_2e (\$2.60b) under the high DER uptake assumptions.
• Based on the capabilities tested within the CBA scenarios, the benefits will be driven by: - DOE configurations that enable high customer coverage and target maximum utilisation of the distribution network by DER and VPPs. - A data hub approach to a scalable DER data exchange that reduces integration costs and allows access to a greater scope of service opportunities for DER aggregators serving customers. - A Local Services Exchange (LSE) providing a scalable and standardised market arrangement for DNSPs to source network support services through DER aggregators - Visibility of DER providing the market operator and DNSPs improved awareness of where DER are installed on the network and how they behave.
• DOE customer coverage is the key enabler for delivering benefits. Adequate services (from DNSPs / DER aggregators) must be available to capitalise on the network capacity unlocked from a DOE rollout. It is expected these services and capabilities will need to develop over time.
• Active DER participation in Virtual Power Plants (VPPs) is critical to realise the benefits associated with the capabilities assessed within the CBA scenarios. This will enable DER to make a coordinated response to market prices and system security events at scale.
• Conservatively, several additional benefits are identified but not quantified or included in the CBA due to limitations in data availability. These include V2G coordination, compounding effect of market configurations on DER uptake and additional DER services.
• The benefits accrue across multiple market participants (e.g. DER aggregators/retailers (and as a consequence DER consumers), DNSPs, TNSPs and the market operator).
• A data hub approach to DER data exchange compared to a point-to-point approach will lower integration and registration costs across market participants. A data hub approach could also allow new DER-based service innovations to be adopted more easily.
• The cost differential between a centralised and decentralised data hub is not material.
• The decentralised data hub has the potential for a shared governance and ownership model with the aim of better facilitating participants to innovate and deliver services to DER customers.

- Costs to implement an LSE via a data hub arrangement, as compared to the alternative point-to-point arrangement, would be lower. An LSE can also reduce DER export curtailment given its ability resolve network constraints.
- The Project EDGE arrangement of roles and responsibilities underpins the realisation of benefits identified in the CBA. In particular, it allows opportunities for value stacking and prioritisation of the interests of DER customers in how their DER is utilised.
- The CBA identified the following as immediate foundational priorities for unlocking the benefits of DER:
  - Increasing customer coverage of DOEs
  - Increased visibility of DER for the market operator and DNSPs
  - The implementation of a scalable data hub to facilitate the above
  - Set clear roles and responsibilities where DER aggregators optimise DER on customers' behalf.
- There is merit in gradually introducing in a targeted manner more advanced DOE configurations (e.g. LV impedance model optimisation methodology and a maximise service DOE objective function).
- The optimal timing for the introduction of an LSE is less clear but should be based on the identification of network constraints.
- There is an immediate opportunity to progress on unlocking the benefits of DER through:
  - Removing consumer constraints on solar exports for as many customers as possible so all consumers can benefit from VPPs coordinating DER
  - Setting the rules for efficient DER coordination with a clear set of roles and responsibilities for market participants
  - Laying the foundations for DER market-enablement with an efficient and scalable data exchange approach to reduce costs and expand consumer choice.
- Timely action in implementing the capabilities identified in this CBA will help realise considerable consumer value, drive emissions reduction and help secure, reliable operation of the NEM as we move towards a higher DER future.

3.1 Context

As part of Project EDGE, Deloitte Access Economics and Energeia conducted a cost benefit analysis (CBA), to provide insights and direction to energy market participants and policy makers of the economic value for all consumers based on evidence from the Project EDGE arrangement for DER participation in the NEM.

The CBA uses where practical the most recent forecasts to explore a range of scenarios under which DER participation within the NEM would align with the long-term interests of electricity consumers across a 20-year time horizon (FY23-FY42).

The purpose of the CBA is to enable policy makers and industry leaders to identify a cost-effective pathway to enact the changes necessary to progress this transition to a higher DER future. The CBA is ultimately an economic assessment. Prepared in consultation with industry stakeholders, the central theme of the CBA was the use of market inputs to test the outcomes of the Project EDGE field trial under 'as real' conditions of the NEM at the time of quantification.

While the outcomes of the CBA represent only a moment in time, this assessment serves as a credible, evidence-based guide for key stakeholders tasked with crafting the next phase of work for the energy transition.

3.2 Approach

The CBA's assessment and subsequent outcomes considered two scenario sets, the first of which reflects a likely future state (scenarios 1-5) and the second of which represents a more accelerated rate of DER uptake (scenarios 6-10).

All 10 scenarios tested in the CBA measure the costs and benefits of more active DER participation in the NEM. Measurements are based on different:

- Load and DER uptake assumptions
- Dynamic Operating Envelope (DOE) configurations, which differ by update frequency, customer coverage, calculation methodology and objective function
- Market configurations (such as scalable DER data exchange approaches and LSE).

The CBA used the following load and DER uptake assumptions:

1 The 2022 Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) step change load and DER uptake assumptions[99] (AEMO ISP step change), reflected in Scenarios 1-5

2 A set of high DER load and uptake assumptions[100] (high DER), reflected in Scenarios 6-10.

Two scenarios are classified as base cases in the CBA (Scenarios 1 and 6).[101] The base cases assume:

- A simplistic DOE configuration and a point-to-point approach to scalable DER data exchange
- The implementation of rule changes requiring new DER installations to comply with DOEs and satisfactory DER customer products to enable active DER to be separately managed from passive load
- No implementation of Scheduled Lite type participation arrangements, limiting market operator and DNSP visibility of DER (however, all other scenarios assume Scheduled Lite to account for the incremental impact).[102]

Subsequent scenarios reflect a gradual increase in complexity against the base cases of the selected capabilities of DER participation. Figure 23 outlines the key arrangements of each scenario.[103]

99 AEMO. 2022, 2022 Integrated System Plan. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

100 Energeia. 2021, Renew DER Optimisation (Stage II): Final Report, p 4; p 32. https://energeia.au/wp-content/uploads/2022/03/Renew-DER-Optimisation-Final-Report-210930v2_compressed.pdf

101 Given that two separate forecast load and DER uptake assumptions are used, Scenario 1-5 outcomes should not be directly compared with Scenario 6-10 outcomes. Scenarios 2-5 are compared to Scenario 1, while Scenarios 7-10 are compared to Scenario 6.

102 AEMO. N.d., Scheduled Lite. https://aemo.com.au/en/initiatives/trials-and-initiatives/scheduled-lite.

103 Detailed information on the Project EDGE CBA Methodology is published at Deloitte. 2022, Project Edge CBA – Methodology. https://aemo.com.au/-/media/files/initiatives/der/2022/project-edge-cba-methodology.pdf?la=en.

Figure 23 | CBA scenarios[104]

		Scenario 1 Base case	Scenario 2 Simple DOE, Moderate Coverage	Scenario 3 Simple DOE, Moderate Coverage with Data Hub	Scenario 4 Advanced DOE, High Coverage	Scenario 5 Advanced DOE, High Coverage with Data Hub
Based on AEMO ISP Step Change forecast load and DER uptake assumptions						
Dynamic Operating Envelope (DOE) configurations	Constraint Optimisation Frequency	Annual	Daily	Daily	Intra-day	Intra-day
	DOE Customer Coverage	VPP only	VPP only	VPP only	100%	100%
	DOE Optimisation Methodology	Approximation	Approximation	Approximation	LV impedance model	LV impedance model
	DOE Objective Function	Nameplate	Maximise service	Maximise service	Maximise service	Maximise service
Market configurations	Scalable Data Exchange	Point-to-point data exchange approach	Point-to-point data exchange approach and LSE	Data Hub & LSE	Point-to-point data exchange approach and LSE	Data Hub & LSE
	Local Services Exchange (LSE)					

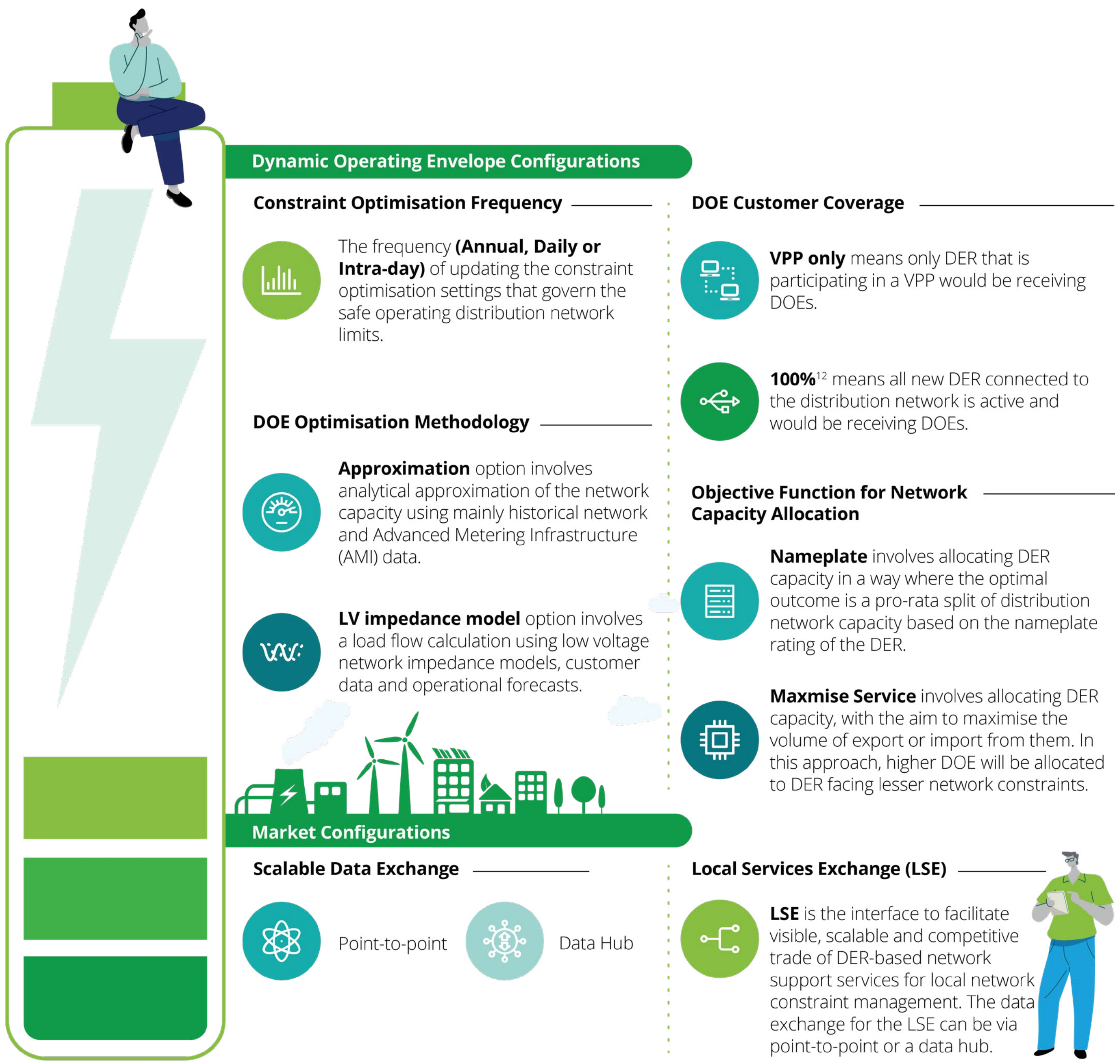
		Scenario 6 Base case	Scenario 7 Simple DOE, Moderate Coverage	Scenario 8 Simple DOE, Moderate Coverage with Data Hub	Scenario 9 Advanced DOE, High Coverage	Scenario 10 Advanced DOE, High Coverage with Data Hub
Based on High DER forecast load and DER uptake assumptions						
Dynamic Operating Envelope (DOE) configurations	Constraint Optimisation Frequency	Annual	Daily	Daily	Intra-day	Intra-day
	DOE Customer Coverage	VPP only	VPP only	VPP only	100%	100%
	DOE Optimisation Methodology	Approximation	Approximation	Approximation	LV impedance model	LV impedance model
	DOE Objective Function	Nameplate	Maximise service	Maximise service	Maximise service	Maximise service
Market configurations	Scalable Data Exchange	Point-to-point data exchange approach	Point-to-point data exchange approach and LSE	Data Hub & LSE	Point-to-point data exchange approach and LSE	Data Hub & LSE
	Local Services Exchange (LSE)					

Legend: Maturity of DOE and market configurations

Source: Deloitte Access Economic, Project EDGE Executive Summary[105]

Figure 24 outlines the DOE configurations and market arrangements considered in the CBA.

Figure 24 | Arrangements within CBA scenarios[106]



Source: Deloitte Access Economic, Project EDGE Executive Summary[107]

104 The load and DER uptake assumptions for Scenarios 1-5 are based on the 2022 ISP. AEMO. 2022, 2022 Integrated System Plan. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. The load and DER uptake assumptions for Scenarios 6-10 are based on Renew DER Optimisation (Stage III): Final Report. Energeia. 2021, Renew DER Optimisation (Stage II): Final Report, p 4; p 32. https://energeia.au/wp-content/uploads/2022/03/Renew-DER-Optimisation-Final-Report-210930v2_compressed.pdf;

To limit the number of CBA scenarios, the impact of each DOE configuration tested within the CBA has not been isolated (e.g., from Scenario 3 to Scenario 4 both the DOE customer coverage and DOE optimisation methodology change);

All scenarios assume 41% VPP participation (as a % of storage) by 2030 and 52% VPP participation (as a % of storage) by FY42.

105 Deloitte Access Economics. 2023, Project EDGE CBA Executive Summary, p 8. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

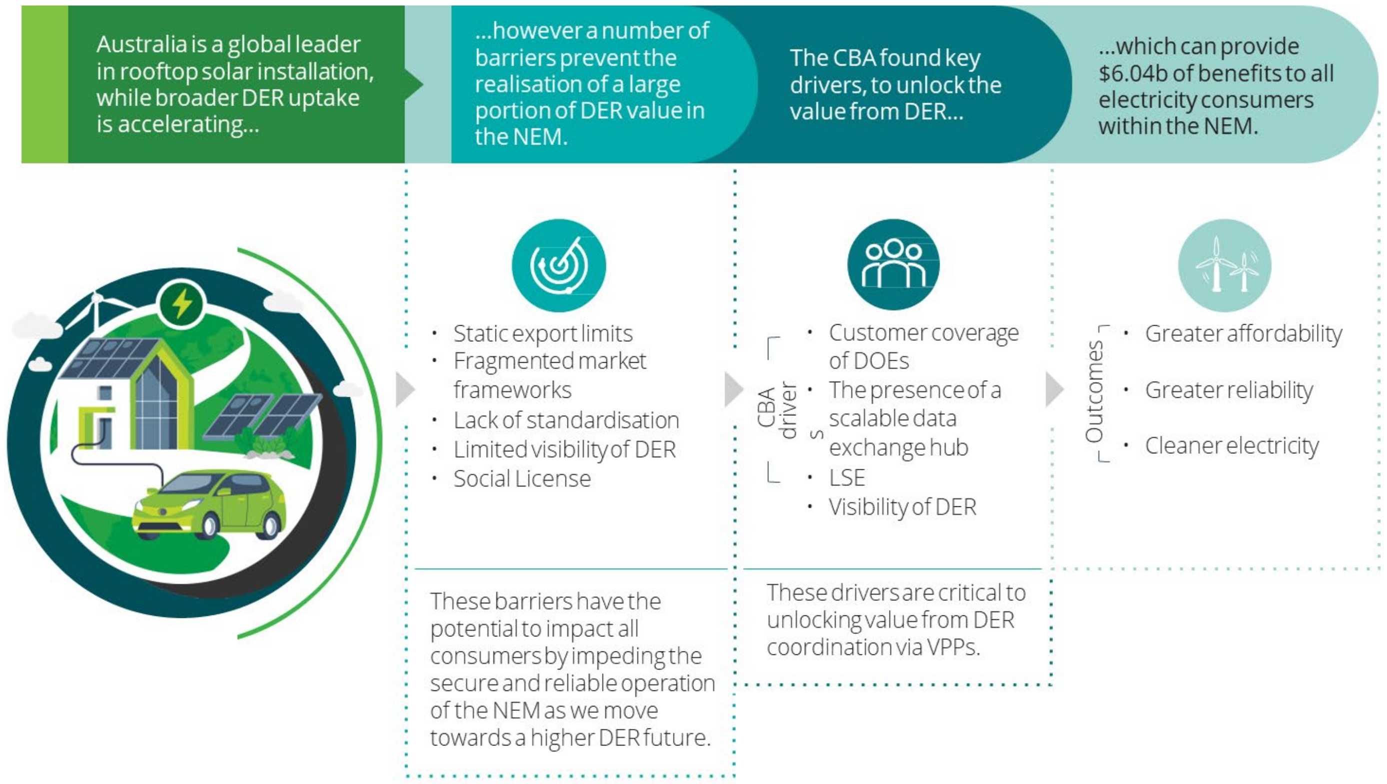
106 100% DOE Customer Coverage is intended to represent a 'bookend' scenario and is not intended to represent an expected future.

107 Deloitte Access Economics. 2023, Project EDGE CBA Executive Summary, p.9. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

3.3 Findings

This section summarises the key findings from Deloitte Access Economics' CBA. The figure below summarises the CBA's key insights and implications.

Figure 25 | CBA summary of insights and implications[108]



Source: Deloitte Access Economic, Project EDGE Executive Summary[109]

3.3.1 All consumers stand to benefit from accelerated and optimised integration of active DER via Virtual Power Plants (VPP) in the NEM

As market configurations evolve, the benefits to consumers increase

Consistent with the ESB's DER Implementation Plan[110] energy market bodies and participants are working to integrate and optimise DER to enable it to respond more actively to price signals.

Currently, several barriers prevent DER value from being maximised across the NEM:

- **Static export limits** that result in the curtailment of DER (e.g. lost export)
- **Fragmented market frameworks** for coordination of active DER, restricting the ability to provide both wholesale and local network services from the same DER portfolio
- **Lack of standardisation** in terms of scalable DER data exchange to streamline a mass market approach to active DER
- **Limited visibility** of active DER minimises situational awareness and forward-looking operational and network planning for the market operator and DNSPs
- **Social licence** challenges, for example consumer permission to allow third-party control of their active DER.

These barriers have the potential to impede the secure and reliable operation of the NEM as Australia moves towards a higher DER future.[111]

Project EDGE tested market arrangements to overcome these barriers.

An incremental benefit is shown across all scenarios in comparison to the base cases over the 20-year time horizon. The CBA found that all consumers will benefit from a coordinated market-based approach to DER integration within the NEM (see Figure 26).

INSIGHTS
CBA findings on the benefits of coordinated DER to all consumers

The CBA findings show that greater coordination of active DER in the NEM via the Project EDGE arrangement can result in an incremental benefit of up to **$5.15b under the AEMO ISP step change** DER uptake assumptions and up to **$6.04b under the high DER uptake** assumptions.

The Project EDGE arrangement of roles and market configurations was found to avoid 15.1TWh of customer rooftop solar curtailment to 2030 and up to 90.6TWh across the 20 year time horizon to 2042 under the AEMO ISP step change DER uptake assumptions and avoid 50.1TWh of customer rooftop solar curtailment to 2030 and up to 257.1TWh across the 20 year time horizon to 2042 under the high DER uptake assumptions.

Based on the capabilities tested within the CBA scenarios, the benefits will be driven by:

- **DOE configurations** that enable high customer coverage and target maximum utilisation of the distribution network by DER and VPPs
- **Data hub** approach to a scalable DER data exchange that reduces integration costs and allows access to a greater scope of service opportunities for DER aggregators serving customers
- **Local Services Exchange (LSE)** providing a scalable and standardised market arrangement for DNSPs to source network support services through DER aggregators, who co-optimise network support services and wholesale services within their DER portfolio
- **Visibility of DER** providing the market operator and DNSPs with improved awareness of where DER are installed on the network and how they behave to enhance situational awareness, operational forecasting and network planning functions.

INSIGHTS
Realising the benefits of coordinated DER

Active DER participation in VPPs is critical to realise the benefits associated with the capabilities assessed within the CBA scenarios. This will enable DER to make a coordinated response to market prices and system security events at scale.

108 100% DOE Customer Coverage is intended to represent a 'bookend' scenario and is not intended to represent an expected future

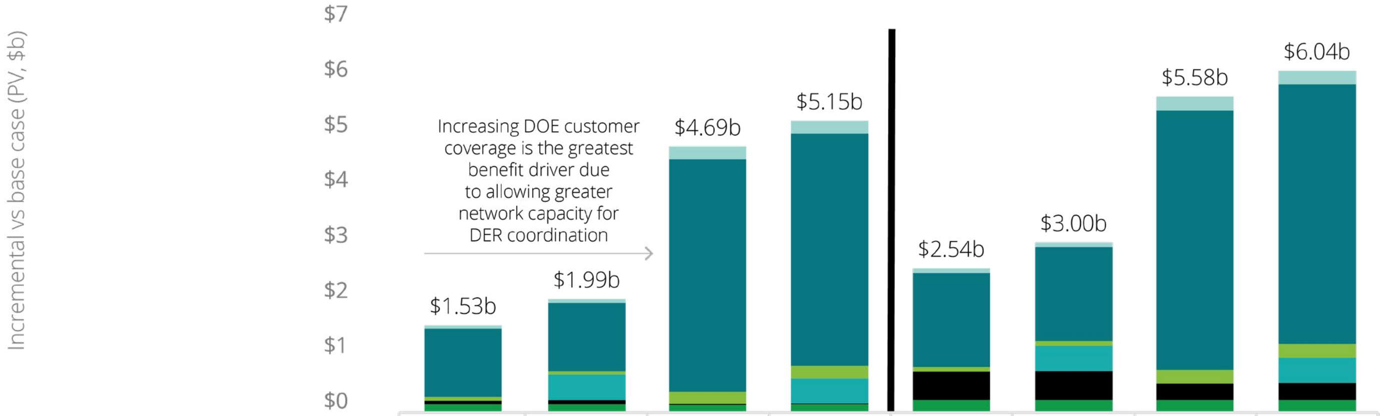
109 Deloitte Access Economics. 2023. Project EDGE CBA Executive Summary. p.24. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

110 ESB. 2021. Clean and Smart Power in the New Energy System. https://esb-post2025-market-design.aemc.gov.au/integration-of-distributed-energy-resources-der-and-flexible-demand

111 AEMO. 2023. 2023 Electricity Statement of Opportunities: August 2023. p 95. https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en

Figure 26 illustrates the increasing benefits to market participants as configurations evolve.

Figure 26 | CBA findings — key drivers of value incremental to the base cases (20-year time horizon, $FY23, 4.83% discount rate)[112]



Key drivers of value across the CBA Scenarios	**Scenario 2** (Simple DOE, Moderate Coverage)	**Scenario 3** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 4** (Advanced DOE, High Coverage)	**Scenario 5** (Advanced DOE, High Coverage with Data Hub)	**Scenario 7** (Simple DOE, Moderate Coverage)	**Scenario 8** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 9** (Advanced DOE, High Coverage)	**Scenario 10** (Advanced DOE, High Coverage with Data Hub)
DOE Constraint Optimisation Frequency (more total network capacity unlocked for DER coordination)	$0.06	$0.06	$0.22	$0.22	$0.08	$0.08	$0.24	$0.24
DOE Customer Coverage (more total network capacity unlocked for DER coordination)	$1.21	$1.21	$4.12	$4.12	$1.67	$1.67	$4.60	$4.60
DOE Objective Function (more network capacity allocated to DER)	$0.06	$0.06	$0.22	$0.22	$0.08	$0.08	$0.24	$0.24
Data Hub (reduced costs and enables additional DER services)	$-	$0.45	$-	$0.45	$-	$0.45	$-	$0.45
LSE (reduced DER curtailment)	$0.07	$0.08	$0.00	$0.01	$0.50	$0.51	$0.29	$0.30
Visibility of DER (enhanced power system operations)	$0.12	$0.12	$0.12	$0.12	$0.20	$0.20	$0.20	$0.20

Notes: A) Total cost in scenario 1 is $192.7b and in scenario 6 is $190.2b. This total is the cost that forms the basis of the incremental present value impact shown across the scenarios.

Source: Deloitte Access Economic, Project EDGE Executive Summary[113]

112 Scenarios 2-5 are compared to Scenario 1, while Scenarios 7-10 are compared to Scenario 6.

113 Deloitte Access Economics. 2023, Project EDGE CBA Executive Summary, p.12. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

3.3.1.1 **Additional emerging customer benefits**

The EDGE CBA provides a relatively conservative estimate of the benefits as there are several additional qualitative benefits not accounted for in the CBA due to limitations in data availability. These include:

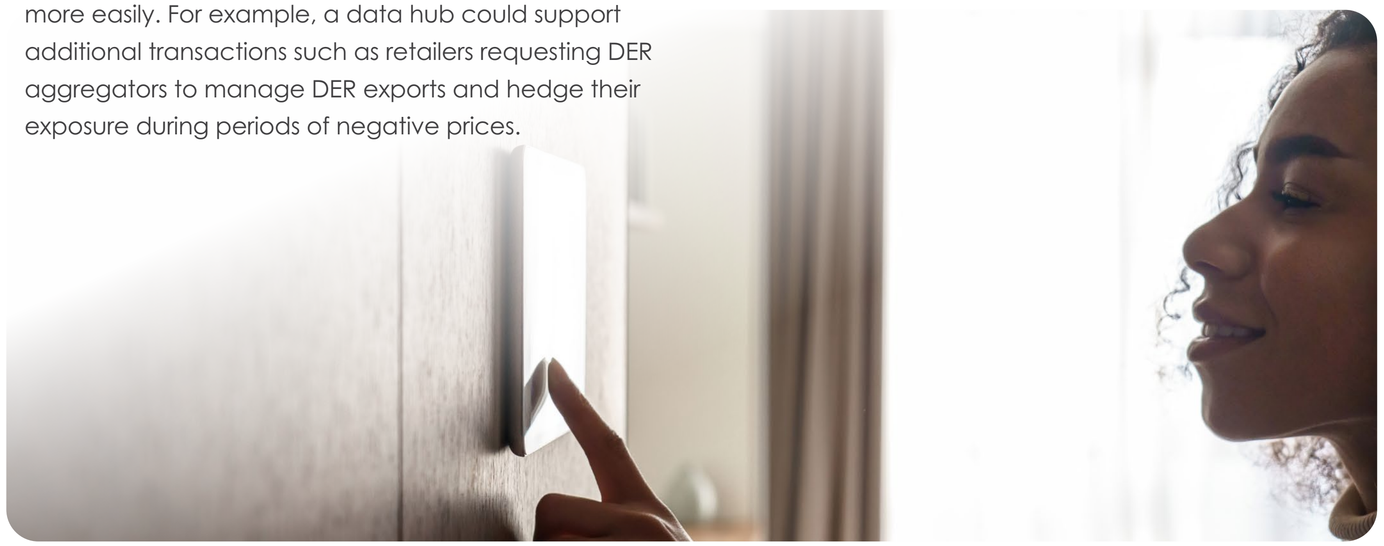
- **V2G coordination,** given the increasing uptake of EVs in Australia[114], V2G (EV charging and discharging into the grid) is expected to increase the opportunity and value associated with coordinated DER participating in a VPP (due to more DER capacity to coordinate). The CBA does not quantitatively consider the impact of V2G given its nascency at the time of project design. However, it is expected that further value realisation will be possible from the coordination of greater DER capacity.
- **Compounding effect of market configurations on DER uptake** – the effective integration of DER in the NEM via market configurations (e.g. scalable DER data exchange and LSE) that enable cost reductions or access to a greater scope of service opportunities for DER aggregators could result in direct or indirect incentives to install more DER and increase VPP uptake by customers.
- **Additional DER services** – effective market arrangements have the potential to facilitate further value from DER as industry maturity and needs evolve by enabling new DER-based service innovations to be adopted more easily. For example, a data hub could support additional transactions such as retailers requesting DER aggregators to manage DER exports and hedge their exposure during periods of negative prices.

3.3.1.2 **Relevance of findings by market participant type**

The CBA aligns costs and benefits to market participant types. The CBA findings across market participants show:

- Increased revenue opportunities for DER aggregators[115] and, as a consequence, DER consumers due to:
  - A reduction in DER export curtailment
  - Partial displacement of large generators enabled via wholesale integration of active DER[116]
  - The provision of contingency Frequency Control Ancillary Services (FCAS) and local network support services
  - Reduced DER data exchange costs.
- Lower DNSP costs in maintaining and increasing the capacity of the distribution network and reduced DER data exchange costs
- Lower TNSP costs in maintaining and increasing the capacity of the transmission network
- Lower market operator costs through reduced DER data exchange costs and enhanced management of power system security issues due to greater visibility of active DER.

Figure 27 outlines the CBA findings across these market participants noting that all consumers can benefit from the accelerated and optimised integration of active DER in the NEM

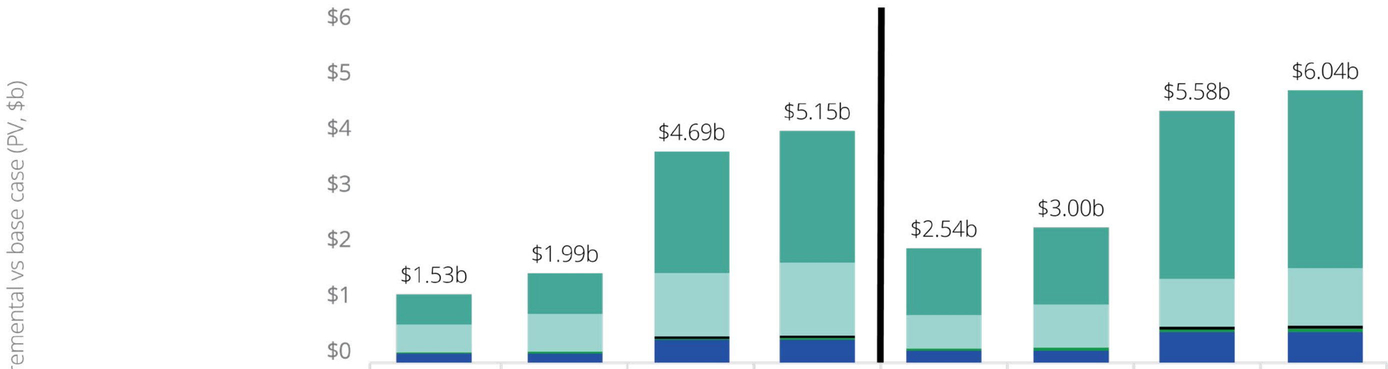


114 As of the end of June 2023, 46,624 EVs had been sold in Australia – almost 3 times higher than the same period in 2022 (a 269% increase). Electric Vehicle Council. 2023, State of Electric Vehicles, p.8. https://electricvehiclecouncil.com.au/wp-content/uploads/2023/07/State-of-EVs_July-2023_.pdf

115 The value that is captured by DER aggregators (i.e. realised revenue) will depend on their respective business models (e.g. capitalising on arbitrage opportunities) and customer acquisition costs.

116 This results in the reduction of generation costs (e.g. build, operational and maintenance costs) needed to meet energy demand across the NEM. This is partially enabled by more advanced DOEs and greater active participation of DER in VPPs, and it is therefore assumed DER aggregators will capture some of the value associated with this.

Figure 27 | CBA findings across market participants (20-year time horizon, $FY23, 4.83% discount rate)[117, 118]



	Scenario 2 (Simple DOE, Moderate Coverage)	Scenario 3 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 4 (Advanced DOE, High Coverage)	Scenario 5 (Advanced DOE, High Coverage with Data Hub)	Scenario 7 (Simple DOE, Moderate Coverage)	Scenario 8 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 9 (Advanced DOE, High Coverage)	Scenario 10 (Advanced DOE, High Coverage with Data Hub)
DER Aggregators (includes Retailer VPPs) and DER Customers	$0.68	$0.90	$2.70	$2.93	$1.48	$1.71	$3.73	$3.95
DNSPs	$0.62	$0.84	$1.41	$1.62	$0.74	$0.96	$1.07	$1.28
TNSPs	$0.00	$0.00	$0.06	$0.06	$0.00	$0.00	$0.06	$0.06
Market Operator	$0.02	$0.04	$0.02	$0.04	$0.05	$0.07	$0.05	$0.07
Other (FCAS and Visibility of DER)	$0.20	$0.20	$0.50	$0.50	$0.26	$0.26	$0.68	$0.68

Notes: Total cost in scenario 1 is $192.7b and in scenario 6 is $190.2b. This total cost is the cost that forms the basis of the incremental present value impact shown across the scenarios

Source: Deloitte Access Economic, Project EDGE Executive Summary[119]

3.3.2 A data hub approach to scalable DER data exchange will reduce costs and facilitate additional DER service opportunities more effectively compared with a point-to-point approach

A data hub approach reduces costs by up to $0.45b compared to a point-to-point approach

A data hub model provides a lower cost approach for scalable DER data exchange between participants, compared with an approach with many point-to-point interactions, by reducing the number of integrations, as each participant only needs to integrate with the industry data hub once.

The CBA found that across the 20-year time horizon, a centralised data hub reduces costs by up to $0.44b and a decentralised data hub reduces costs by up to $0.45b as compared to a point-to point approach.

In addition, a data hub as compared to a point-to point approach can deliver further upside through facilitating new DER-based service innovations more easily and at lower cost as it simplifies integration, identity verification and reporting between participants. Additional DER services support greater coordination of DER, which drives value to all consumers.

117 This figure assumes that DER aggregators capture all the value of displacing large generators enabled by more advanced DOEs and greater active participation of DER in VPPs and all value associated with the delivery of local network support services. In reality, DER aggregators would likely capture a significant portion but not all of this value.

118 'Other' relates to broader 'whole of system' impacts as compared to a specific market participant.

119 Deloitte Access Economics. 2023. Project EDGE CBA Executive Summary. p.15. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

3.3.3 A Local Services Exchange can provide cost-effective alternatives for DNSPs seeking network support services

Establishing an LSE (with a data hub approach) can yield an incremental benefit between $0.08b and $0.51b

Establishing an LSE for scalable and competitive trade of standardised DER-based network support services enables DER aggregators to offer and deliver network support services at a lower cost. Without prohibitive transaction costs, DER aggregators can provide DNSPs with a reliable alternative to expensive network augmentation options.

In Project EDGE, DER aggregators used the same portfolio of DER to offer and deliver both wholesale and network support services, effectively creating further value from the same consumer DER assets.

The CBA found that the costs to implement an LSE via a data hub arrangement, as compared to the alternative point-to-point arrangement, would be $9m lower. This is due to the reduced number of integrations required – as noted in the previous section, each participant only needs to integrate with the data hub once.

Further, the Project EDGE field trial demonstrated from a technical perspective that aggregated DER can be reliably used to deliver local network support via both demand management and voltage management services.

The assessment of value from an LSE has been informed by the UoM research paper, which noted that the value of network support services is directly linked to their ability to resolve network constraints that are locational and temporal. The CBA has adopted a conservative approach to valuing the benefits of an LSE, based only on its use to reduce DER export curtailment, and excluding due to insufficient data potential benefits related to its use to maintain the reliability and quality of electricity supply in the distribution system. To simplify the process of assigning a value to the use of an LSE to reduce DER export curtailment, the CBA has derived an average price associated with reduced curtailment, using the 2022 customer export curtailment values (CECV) published by the AER. This price has been applied to the forecast annual volume of curtailed exports.

The CBA found that across the 20-year time horizon the implementation of an LSE (with data exchange via a data hub) can result in an incremental benefit of up to $0.08b under the AEMO ISP step change assumptions and up to $0.51 under the high DER uptake assumptions. These findings indicate clear value in establishing an LSE. However, this calculated value is deliberately conservative as it relates to a subset of use cases for LSE and accordingly represents only a portion of the potential applications of an LSE.

3.3.4 The Project EDGE arrangement of roles and responsibilities underpins the realisation of benefits identified in the CBA

Roles and responsibilities adopted for Project EDGE enable several features critical to successfully coordinating and integrating DER into the NEM

An important aspect of understanding the value of integrating DER into the NEM was the examination within the CBA of the roles of market participants and the responsibilities assigned to those roles.

As described in Chapter 1, from 2018 to 2020, AEMO and ENA undertook OpEN to explore different market frameworks to cost-effectively integrate DER into the NEM.

OpEN proposed the Hybrid Model as the most suitable framework for integrating DER. It also proposed that trials should be conducted to understand how a Hybrid Model could best integrate DER. Accordingly, the arrangement of roles and responsibilities in the Project EDGE field trial were based on this model.

INSIGHTS
Benefits of aggregators optimising DER on behalf of customers

The CBA found the Project EDGE arrangement of roles and responsibilities, whereby DER aggregators, on behalf of DER customers, receive the necessary external signals (such as prices and constraints) and optimise DER portfolios across wholesale and B2B opportunities (e.g. network support services) allows:

- Prioritisation of the interests of DER customers in how their DER is utilised – this is particularly important in a voluntary, market-based arrangement where customers who have invested in DER need to perceive clear value in participating in the NEM through a DER aggregator
- Streamlined visibility with all service capacity (for market and B2B services) of a portfolio represented in a common portfolio level bid to the market operator
- Opportunities for value stacking, which can allow for greater value customer products and cost efficiencies to be realised by DER aggregators
- An appropriate allocation of risks and incentives as DER aggregators are responsible for optimising DER resources while acting in compliance with market rules and connection agreements.

The Project EDGE arrangement of roles and responsibilities aligns to the NEO and promotes efficiency by extending current roles and responsibilities rather than creating new or duplicating existing ones.

3.3.5 Action on priority areas will progress the foundational capabilities for unlocking the benefits of DER

Industry and policy makers will need to work together to map out a clear, progressive and cost-effective pathway to a high DER future

The CBA identified the following as immediate foundational priorities for unlocking the benefits of DER:

- **Increasing customer coverage of DOEs** as this enables greater DER export capacity
- **Increased visibility of DER for the market operator and DNSPs**, to enable situational awareness of DER in the NEM.
- **The implementation of a scalable data hub to reduce data exchange costs** data exchange costs (and hence barriers to entry) for market participants (e.g. in accessing DOEs or gaining visibility of DER) and supports the development of additional DER service opportunities (including B2B services) that can support greater coordination of DER, which drives value to all consumers
- **Set clear roles and responsibilities** where DER aggregators optimise DER on customers

These priorities are foundational to unlocking value from DER coordination via VPPs.

The CBA found there is merit in gradually introducing in a targeted manner more advanced DOE configurations (e.g. LV impedance model optimisation methodology and a maximised service DOE objective function). The introduction of these DOE configurations should be prioritised based on where DER are most constrained due to network capacity limits. While DOEs have the ability to release more network capacity for DER at times of constraint, realising the value of that additional capacity will require a sufficient proportion of installed DER to be connected under flexible connection agreements and made active through DER aggregators.

The optimal timing for the introduction of an LSE is less clear. While the Project EDGE field trial indicated that the LSE can technically deliver local network support services today, there are several factors that influence the value delivered by an LSE. For example, LSE services are only viable where DER aggregators can represent and offer sufficient DER capacity at confined locations where that support is required, as network constraints are by their nature locational and temporal.[120] As an initial step, DNSPs should consider targeting implementation of LSE for parts of the network with known constraints.

120 S. Riaz, J. Naughton, UOM. 2023, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches. In press

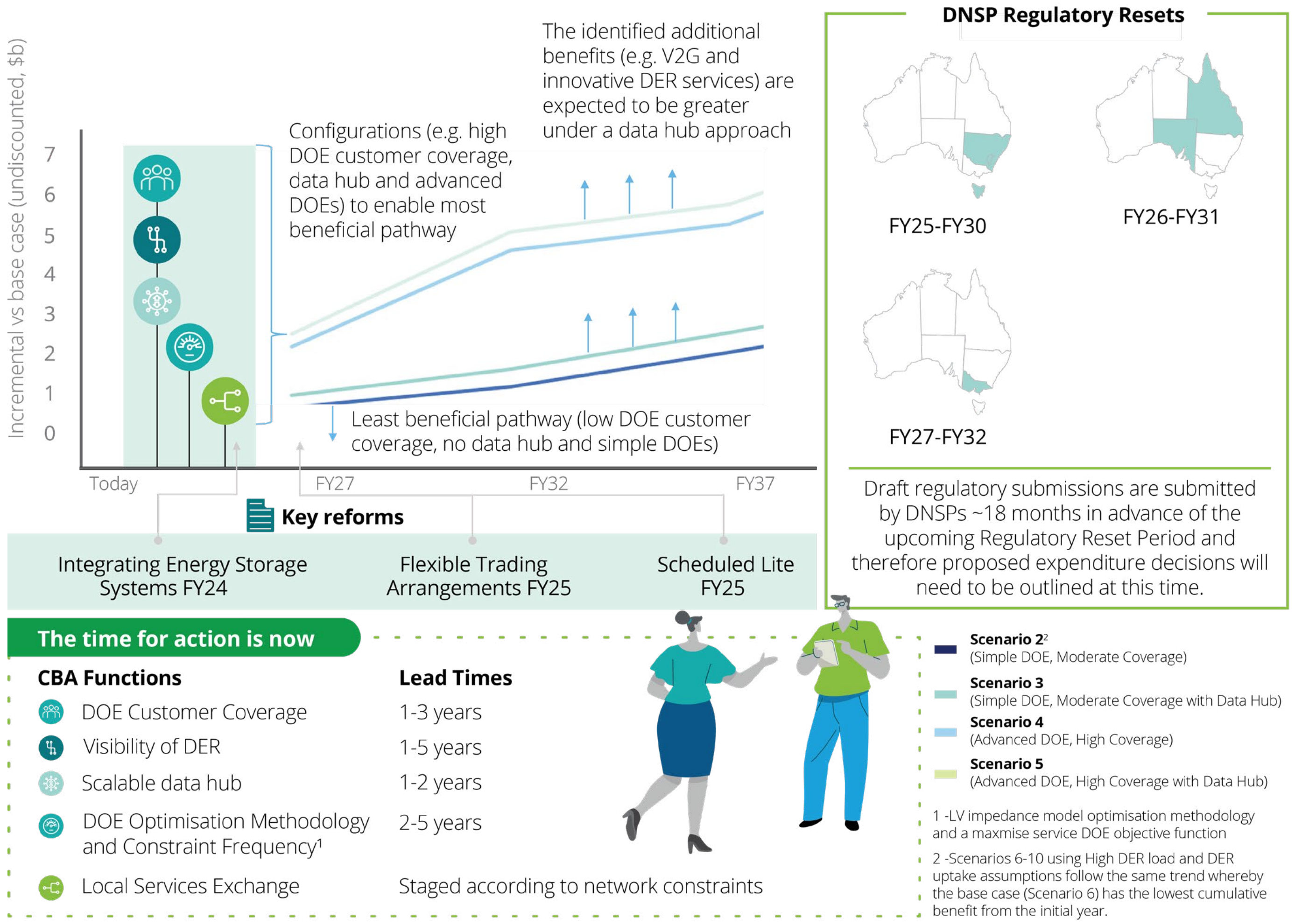
3.3.5.1 The DER Optimal Investment Pathway

The CBA found that the broad deployment of DOEs for many DER customers and the establishment of a scalable data exchange hub are short-term priorities necessary for the longer-term delivery of value from DER.

Figure 28 summarises a potential DER investment pathway for key industry capabilities, to realise the benefits identified in the CBA. This figure takes into consideration key upcoming market activities and estimated lead times for the capabilities tested within the CBA, to help inform planning.

Ultimately, it highlights a DER investment pathway that hinges on focused and coordinated action from policy makers and market participants.

Figure 28 | DER Investment Pathway



Source: Deloitte Access Economic, Project EDGE Executive Summary[121]

121 Deloitte Access Economics. 2023, Project EDGE CBA Executive Summary, p.20. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

3.4 Key insights and implications for industry

Project EDGE notes the following key insights and implications for industry.

For policy makers

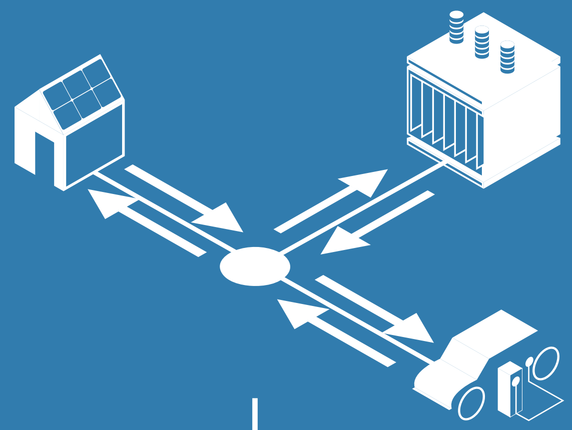
- When making decisions, consider the finding of the Project EDGE CBA that four priorities are foundational to unlocking value from DER coordination via VPPs:
  - Increasing customer coverage of DOEs
  - Increased visibility of DER for the market operator and DNSPS
  - Implementation of a scalable DER data hub to support the above
  - Clear roles and responsibilities where DER aggregators optimise DER on customers' behalf.
- Prioritise the enablement of flexible export limits to support DOE customer coverage. Dynamic connection agreements can do this if customers are given clear incentives.
- To promote DOE customer coverage, undertake further work to inform consumers of the benefits of DER integration and to build social licence with customers. Importantly, issues around fairness, transparency of value to customers and trust need to be addressed sufficiently.
- Work with industry to prioritise implementation of a scalable data hub that provides standardised data services such as integration, DER registration, identity and access management to reduce DER data exchange costs and facilitate improved access to additional DER use cases that can support greater coordination of DER, which drives value to all consumers.
- Take a targeted approach to implementing advanced DOE configurations and an LSE based on network needs. Barriers to the adoption of an LSE could be lowered by exchanging the data through a scalable DER data hub and standardising its building blocks while still allowing flexibility to define fit for purpose services. It is reasonable to assert that enabling DER aggregators cost-effective access to additional use cases for their DER fleet promotes choice and innovation.

For AEMO

- Focus on building capabilities relating specifically to DER, leveraging inputs from current reform initiatives such as the proposed 'Integrating price responsive resources into the NEM' ('Scheduled Lite') rule change and DOEs. These capabilities can enable the market operator to know how and in what volumes DER exports will respond to prices and the impact this will have on the market and the ability to forecast effectively. This is aligned with current reform initiatives such as the proposed Scheduled Lite rule change.

For DNSPs

- Consider focusing on investment to uplift monitoring and management of their LV networks and connected DER. This will require DNSPs to invest in monitoring systems and digital platforms to increase visibility and control. These investments will be critical to supporting the increased utilisation of network assets and allowing more of the expanding volume of DER to be brought to market.
- Target implementation of DOEs that are optimised for a given network segment and DER penetration level.
- Target an approach to LSE implementation that enables scalable and competitive trade of standardised NSS.



DYNAMIC OPERATING ENVELOPES DESIGN

This chapter focuses on the research question:

How does operating envelope design impact on the efficient allocation of network capacity while enabling the provision of wholesale energy and local network services?

Overview

- As the amount of DER in the NEM grows, there is a need to change current approaches to managing finite network hosting capacity to maximise both the financial benefits for customers exporting electricity into the grid and economic benefits to the broader power system from DER exports.
- Dynamic connection agreements and associated dynamic operating envelopes (DOEs) have the potential to provide a more efficient approach because they allow DNSPs to vary customer exports to the grid depending on network conditions.
- In Project EDGE, DOEs express dynamic power export and import limits at a customer's connection point to the local grid. They are calculated by DNSPs to allocate 'spare' network hosting capacity among flexible resources, so that power flows remain within distribution network limits across varying conditions based on time, season and location.
- Project EDGE used techno-economic modelling (conducted by UoM) to understand how the design and calculation of DOEs can impact on the fair and efficient allocation of network capacity as DER penetration in the network increases. The project found that:
  - The design of DOEs has material impacts on network operation and the efficient delivery of services. More sophisticated DOEs are more efficient and enable the network to host more DER.
  - A DOE objective function that maximises aggregated exports is the most fair for all consumers.
  - Using a Low Voltage network model to calculate DOEs is the most advanced and accurate approach, and enables more spare network capacity to be allocated. However, obtaining and verifying an LV network model is costly and time consuming. Adequate DOEs can be applied without the need for a full network model and DNSPs could start with simpler approximation-based DOEs to realise value quickly, progressing to more accurate models when DER penetration justifies doing so. Simpler approaches would still provide value compared to static export limits, but they may need to be tuned and tested to ensure that over-allocation of network capacity does not occur.
  - Higher DER participation in VPPs and broad DOE customer coverage can increase network efficiency (through improved utilisation of network capacity from more accurate DOEs). This finding is supported by the CBA, which found a commercial case for as broad DOE customer coverage as possible to unlock greater spare network hosting capacity for DER customers, which would increase value to all consumers.
  - In terms of frequency of DOE recalculation, the closer to real-time a forecast is generated, the more accurate it (and the DOE) are likely to be. However, more frequent forecasts and updates to DOEs come with associated technical and cost implications for DNSPs.
  - Head of feeder voltage forecasts are highly influential on DOE accuracy and efficacy. To maximise the utility of DOEs, future focus should be on improving head of feeder voltage forecasts, as this will also assist in unlocking the potential economic value of more effective DOEs.
- There would be detrimental customer impacts from DOE breaches (potentially caused by an over-allocation of capacity to coordinated DER). Accordingly, industry and regulators should consider DNSP investment in more accurate DOE calculation capabilities as aligning with the NEO's objectives to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interest of electricity consumers.
- Investment in DOE calculation models should be overseen by the AER to ensure it is prudent and efficient and in line with a network's DER penetration levels. There could be a case for periodic analysis (as part of regulatory oversight) of DOEs against perfect hindsight DOEs (representing actual network limits) to make sure DER is not overly constrained beyond what is deemed appropriate.
- Project EDGE also conducted a desktop assessment of capacity optimised DOEs, in which the allocation of available network capacity through DOEs is based on DER capacity forecasts from the aggregator rather than on DER nameplate capacity (the DER rating). The project found that capacity optimisation could be a useful enhancement applied to DOEs for clusters of NMIs. Further investigation of capacity optimised DOEs should be considered as part of a DOE development roadmap, developed collaboratively by industry participants.
- Desktop analysis of field trial data suggests that there is value available from the economic optimisation of network capacity allocation. This potential value is likely to grow with DER participation, and DOE curtailment rates. The value that can be captured is dependent on implementing an efficient system of reallocating network capacity between customers, accordingly, there would be merit in exploring both DOE calculation and market mechanisms.
- A key topic industry will need to resolve is the location of the DOE application (the capacity allocation point). Project EDGE considered two options: allocation at the customer point of connection to the network (referred to as Net NMI DOEs) and allocation only to controllable generation and load (referred to as Flex DOEs). This topic requires further exploration, and it is critical industry agrees on an approach that provides longer term efficiency benefits to the system and all electricity consumers.
- The CBA suggests an accelerated DOE rollout can deliver consumer benefits sooner, particularly if DER uptake continues at the forecast rate. As DOEs are a relatively new concept and would be a significant shift in the way customers are able to use their DER, a progressive approach to DOE implementation should be considered.
- Project EDGE has developed an indicative accelerated DOE road map for consideration by industry. The road map commences with the transition to flexible export limits, introduces simple forecasting models and applies a 'maximise service' objective function. As constraints become more frequent, the road map moves to more frequent and more sophisticated DOEs and more complex forecasting, and then potentially moves to flexible import limits, shaped operating envelopes and grouped DOEs as EV penetration increases.
- This progressive approach would enable the value of DOEs to be realised quickly and allow DNSPs to invest incrementally in network monitoring and more sophisticated model-based DOEs over time, guided by local DER penetration levels.
- It will also be critical that any decisions and solutions around DOEs are sufficiently flexible to work with new market arrangements and can be adapted to support new and innovative business models as DER integration into the power system and markets matures and evolves.

4.1 Context

Electricity distribution networks have a finite capacity to support electricity power flows, including exports from DER and imports to support consumer loads. This is referred to as the network's hosting capacity.

Hosting capacity is typically based on an assessment of diversity adjusted maximum power flows (i.e. an assessment of maximum power flows expected on any given network segment given a mix of customer DER or loads). The continuing and forecast increase in DER adoption in the NEM means parts of distribution networks will reach – or are already reaching – their technical operating limits for rooftop PV exports during midday hours on particular days in the year (typically sunny, mild spring weekends).

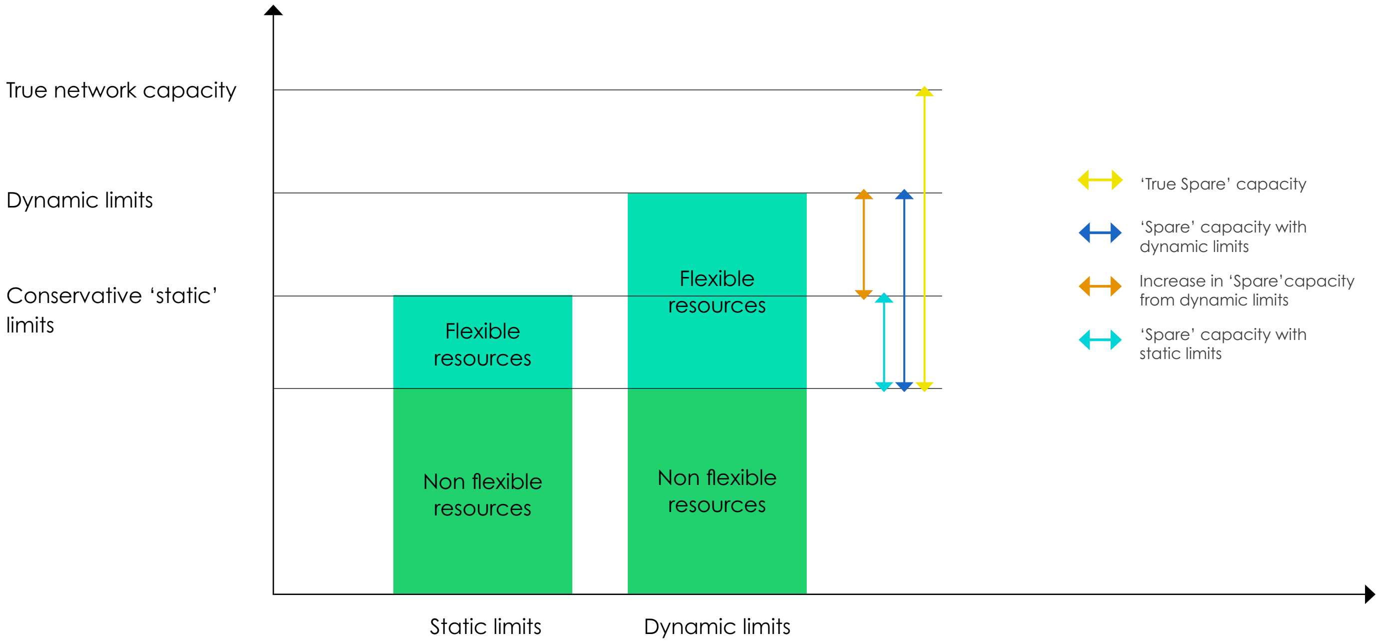
This means DNSPs must limit how much power new DER installations are allowed to export to maintain secure and reliable operation and supply of electricity to all customers connected to the network. Export limits are typically allocated using a set (static) export limit for new DER installations.

Since they are meant to account for worst case scenarios, static limits can be conservative. High rooftop PV penetration is causing static export limits in some areas to be reduced, sometimes to zero, meaning new rooftop PV connections are not able to export to the grid at all. This limits consumers' ability to maximise the financial benefits from exporting electricity into the grid, and it also limits the potential economic benefits to the broader power system from their exports.

There is a need to change current approaches to managing network hosting capacity. Dynamic connection agreements and associated DOEs have the potential to provide a more efficient approach because they allow DNSPs to vary customer exports dynamically depending on network conditions. This would allow customers to export more electricity most of the time, while constraining exports only to the extent, and at times, when it is necessary. This enablement to export more electricity is referred to as improved hosting capacity in this chapter.

DOEs can increase the network's 'spare' hosting capacity by managing exports and imports from DER more efficiently. In Project EDGE, DOEs express dynamic power export and import limits at a customer's connection point to the local grid. They are calculated by DNSPs to allocate 'spare' network hosting capacity among flexible resources[122] (based on the network capacity not used by passive or non-flexible resources) so that power flows remain within distribution network limits across varying conditions based on time, season and location. This is shown in Figure 29.

Figure 29 | Conceptual illustration of space hosting capacity



Notes:
This diagram shows uni-directional limits. DOEs would mirror hits image across the X-axis
In peak demand situation non-flexible resources would push closer to the true network capacity

The design and calculation approach can have an impact on the 'efficiency' of the DOE - that is, the amount of power that the DOE enables to flow through the network compared to true network limits.

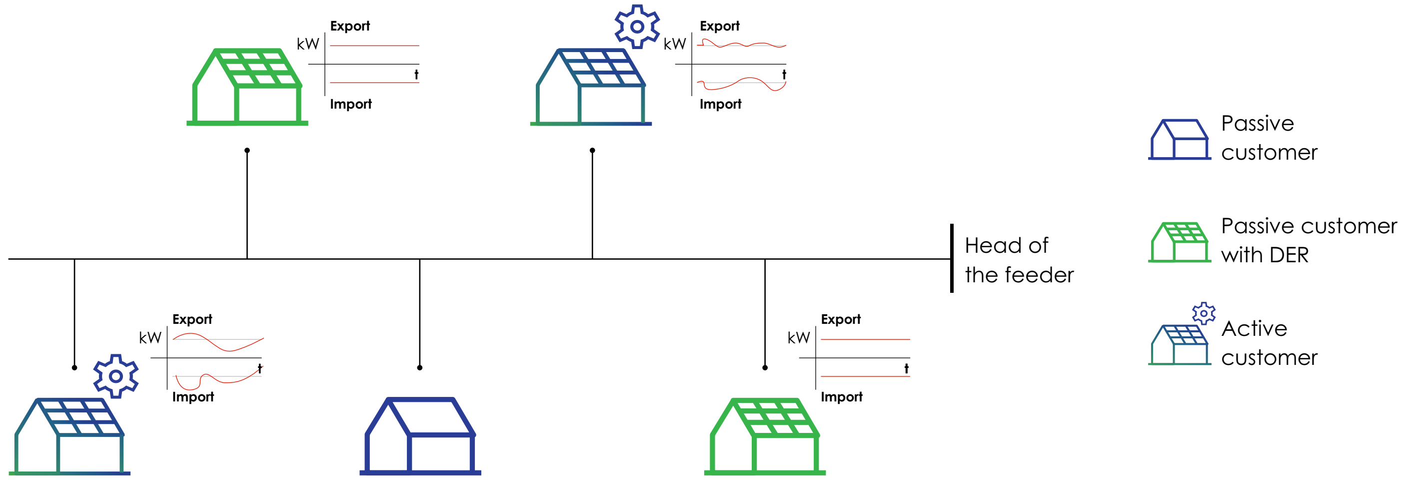
Figure 30 provides a simple illustration of the concept of a dynamic operating envelope.

The blue, green, and multi-coloured houses represent customers with passive load, passive DER and active DER (coordination via a VPP) respectively. The operating envelope (red lines) of passive customers with DER is static.[123] The operating envelopes of active customers are calculated by the DNSP according to network conditions (hence dynamic).

122 Flexible resources in this context means resources at connection points that are receiving and responding to DOEs.

123 The figure does not include a static limit for passive customers without DER (passive load). It is not anticipated DSOs would apply import limits to the passive load for customers without DER as the passive load is considered an essential service. The network is built to the capacity needed to provide this essential service, which is paid for by all customers via their electricity bills, including those customers with DER.

Figure 30 | Conceptual illustration of static versus dynamic operating envelopes



Source: Project EDGE, Project EDGE Fairness in Dynamic Operating Envelope Objective Functions[124]

Note that technically all connections have an import limit through the fuse. For the purposes of the discussion on DOEs and to avoid confusion, no fuse import limit has been shown for the passive customer with no DER.

In Project EDGE, DOEs articulate the spare hosting capacity for exports and imports. In the NEM today, the first emergence of DOEs are applied to export limits only ('flexible export limits'[125]) but could be applied to imports in future (e.g. to manage flexible loads during peak demand events).

While DOEs can enable greater 'spare' hosting network capacity than fixed connection agreements, there is a threshold when the DOE stops being effective. For clarity, the network's hosting capacity is finite and only increases through traditional augmentation of the network. DOEs enable more efficient use of that hosting capacity.

As DER connections in the distribution network increase, lower DOEs would need to be allocated to maintain DER operation within the physical hosting capacity limits.

INSIGHTS
DOEs can inform economic assessments for network augmentation

It is important to note that there may be an economic rationale for network augmentation to increase the physical hosting capacity and reduce the amount of DER curtailment from lower DOEs. Tracking the cost of DER curtailment using DOEs can inform an economic assessment for network augmentation.

124 Project EDGE. 2023. Project EDGE: Fairness in DOE Objective Functions Executive Summary Report, p.2. https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-executive-summary.pdf?la=en

125 SA Power Networks. N.d., Flexible Exports. https://www.sapowernetworks.com.au/industry/flexible-exports/

DEFINITION

Key terms

The following terms are used frequently in the discussion in this chapter. For ease of reference, they are defined again here.

Network hosting capacity: The finite capacity to support consumer essential loads and electricity exports from DER.

Improved network hosting capacity: The spare network hosting capacity enabled by DOEs and allowing additional export of electricity by DER. The improved network hosting capacity can be allocated to DER.

Spare hosting capacity: The network hosting capacity to support electricity exports. Referred to as 'spare' in terms of it being additional to the capacity needed to support essential load.

Efficiency of DOE: Also referred to as DOE efficacy. It is the amount of power the DOE enables to flow through the network compared to true network limit. The more accurate and closer to the true network limit (i.e. the less difference between the true network limit and the DOE), the more efficient it is .

Unallocated capacity: This is a term used in UoM research and refers to the DER rated capacity (e.g. the amount of power a DER could provide) that was prevented from exporting as it was not allocated any network hosting capacity via DOEs.

NMI DOE: Refers to a DOE applied at the individual connection point with the distribution network – the National Meter Identifier (NMI) – allocating import/export limits at the site and including all controlled and uncontrolled devices.

Objective function: A DOE objective function is used in the calculation of DOEs to allocate spare network hosting capacity among participating DER customers. Different objective functions can produce different allocations among customers depending on the objective applied.

4.2 Approach

Project EDGE engaged the UOM to undertake techno-economic modelling and DOE research to understand how the design and calculation of DOEs can impact on the fair and efficient allocation of network capacity as DER penetration in the network increases. UoM also investigated the ability for DER aggregators to utilise that capacity.

UoM's techno-economic modelling involved developing algorithms for DOEs (the subject of this chapter) and use cases for market facilitation and network support analysis (discussed in Chapter 7). UoM's research and analysis included three streams:

1. A high-level assessment of DOE objective functions to understand the various methods by which a DNSP could divide the total available spare hosting capacity between the DER in the network and the impact of trying to do so in a 'fair' way[126]
2. Developing a LV network model[127] to test different DOE design approaches at various DER penetration levels in realistic test distribution networks.[128] Calculating DOEs accurately may require a complete and verified model of the LV network impedances[129] and topology. However, DNSPs may not have access to such a model and obtaining and verifying an LV network model is costly and time consuming. Therefore, UoM also tested an alternative approach that does not require an LV network impedance model, called the 'approximation' methodology.[130] This simpler approximation methodology[131] uses an algorithm based on smart meter data that has been developed by AusNet to generate DOEs for networks where it does not have a validated LV network model
3. Determining the technical and efficacy impact of using forecasts with different update frequencies when creating DOEs.[132] DNSPs using impedance forecast models rely on forecast values for head of feeder voltages and the power[134] of distribution network customers to calculate DOEs. The error in these forecasts will impact the efficacy of DOEs. The analysis sought to understand the potential benefits of more frequent forecasts and updates to DOEs.

Project EDGE publications of the UoM study contain additional findings, details on the study design and contextual considerations for some of the findings.

In addition to UoM's work, the following research and analysis activities informed the insights on DOE design and calculation:

- **Field trials:** Data from behaviour and performance in the Project EDGE field trials was analysed to inform how aggregators performed under the approximation algorithm and the LV network model DOEs. Field trial data was also analysed to assess conformance to DOEs when dispatched (discussion of analysis and insights regarding conformance with DOEs is in section 5.3.2.6).
- **Theoretical desktop analysis of field trial data:** The desktop analysis comprised the following research activities:
  1. **Flex DOEs:** This desktop analysis differed from data analysis of actual performance because it used 'pseudo' Flex DOES calculated using field trial data to evaluate DOE approaches that were not implemented in the field trial. The aggregator's unconstrained bi-directional offer (i.e. a bid and offer of the available capacity that could have been offered if a DOE did not apply) data was then used to assess how the aggregator theoretically may have been constrained or how much spare hosting capacity it could have utilised, had a Flex DOE been applied, compared to how it actually performed under a Net NMI DOE.

The pseudo-Flex DOE calculated for this assessment was a simplified version (perfect hindsight Net NMI DOE minus actual uncontrolled power forecast(net)) of what an actual Flex DOE would likely be in practice.

126 Project EDGE. 2023, Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne. https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

127 The LV network model requires the DNSP to input the forecast active and reactive power set point on non-participating customers (i.e. consumers not participating in a VPP) and forecasts of the head of feeder (the secondary side of the LV transformer). The algorithm calculates the optimal allocation while ensuring network constraints are maintained.

128 The modelling included realistic test networks. The models were of typical network configurations, including actual network data. These are representative models of network types (e.g. city network, suburban network). Project EDGE. 2023, Testing Different DOE approaches at DER penetration levels in real-world networks. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge--testing-different-doe-approaches-at-der-penetration-levels-in-realworld-networks--work.pdf?la=en

129 Impedance is a measure of the opposition to electrical flow.

130 This methodology still needs to know the topological relationship between the NMI and the distribution transformer, and also what phase the NMI is on.

131 The approximation algorithm model developed by AusNet does not require forecasts of the network state (active power, reactive power, voltage) to operate. Rather, it uses the historical four weeks of LV transformer data to determine the available hosting capacity per phase with a 98% confidence interval. It then uses historical four weeks customer voltage data to estimate the 99th percentile voltage profile of each customer.

132 Project EDGE. 2023, Determining the Impact of Update Frequency on Operating Envelope Efficacy. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-determining-the-impact-of-update-frequency-on-operating-envelope-efficacy--workstream-3.pdf?la=en

133 NMI-level DOEs that are calculated using impedance forecast models need head of feeder value forecasts. Total hosting capacity DOEs that are calculated using an approximation approach do not need head of feeder forecasts.

134 For active DER customers, this uses reactive power (could be export and import) to calculate the active power. For passive customers, aggregate reactive and active power is used.

DEFINITION

Flex DOE

Flex DOE refers to a DOE applied at the flexible device level (assigned to controllable load and generation only) and excluding native, uncontrolled load.

2 **Perfect hindsight comparison:** The other desktop analysis compared the eight permutations of DOE calculation methods and objective functions (see section 4.3.3) tested in the Project EDGE field trial (field trial DOEs) against theoretical DOEs referred to as 'perfect hindsight DOEs' to assess the accuracy of the field trial DOEs. Perfect hindsight DOEs were generated using the DNSP Distributed Energy Resources Management System (DERMS) after the fact with 100% knowledge of what happened on the network and what spare capacity remained.

Both LV network model and approximation algorithm perfect hindsight models are characterised by actual voltage and current data readings forming the inputs, hence their name. A perfect hindsight DOE defines the maximum power that could be theoretically dispatched without compromising the stability of the distribution network

- **Literature reviews:** Case studies of trials that have used alternative DOE calculation and point of allocation approaches that were not tested in Project EDGE were reviewed.
- **Deakin's consumer research:** As part of its consumer research, Deakin explored perceptions of 'fair' policies regarding approaches to manage DER exports.

Through the LV network model developed by UoM, Project EDGE tested the most sophisticated end of the spectrum in terms of the accuracy that might be possible with DOEs. However, as noted above, this model may not be applicable or feasible to implement for all DNSPs.

Similarly, as the approximation algorithm developed by AusNet makes use of smart meter power quality data, this methodology cannot be used if there is not close to 100% coverage of smart meters. Therefore, other similar, simpler models implemented by other DNSPs may have different results.

DOEs can be calculated in different ways depending on the network's available infrastructure and data, and can vary in complexity and accuracy.[135] The complexity is associated with the required infrastructure and data and the calculation methodology. Meanwhile, accuracy is related to how precise the DOE calculation is.

Although the two calculation models tested in Project EDGE may not be directly replicated by other DNSPs, the findings discussed in this chapter nonetheless provide DNSPs and industry with key insights to inform their approaches to DOE calculation and allocation.

Section 4.3 discusses key insights and implications. It highlights considerations for industry and concludes with a roadmap for accelerated DOE development. Section 4.4 identifies next steps to consider.

4.3 Findings

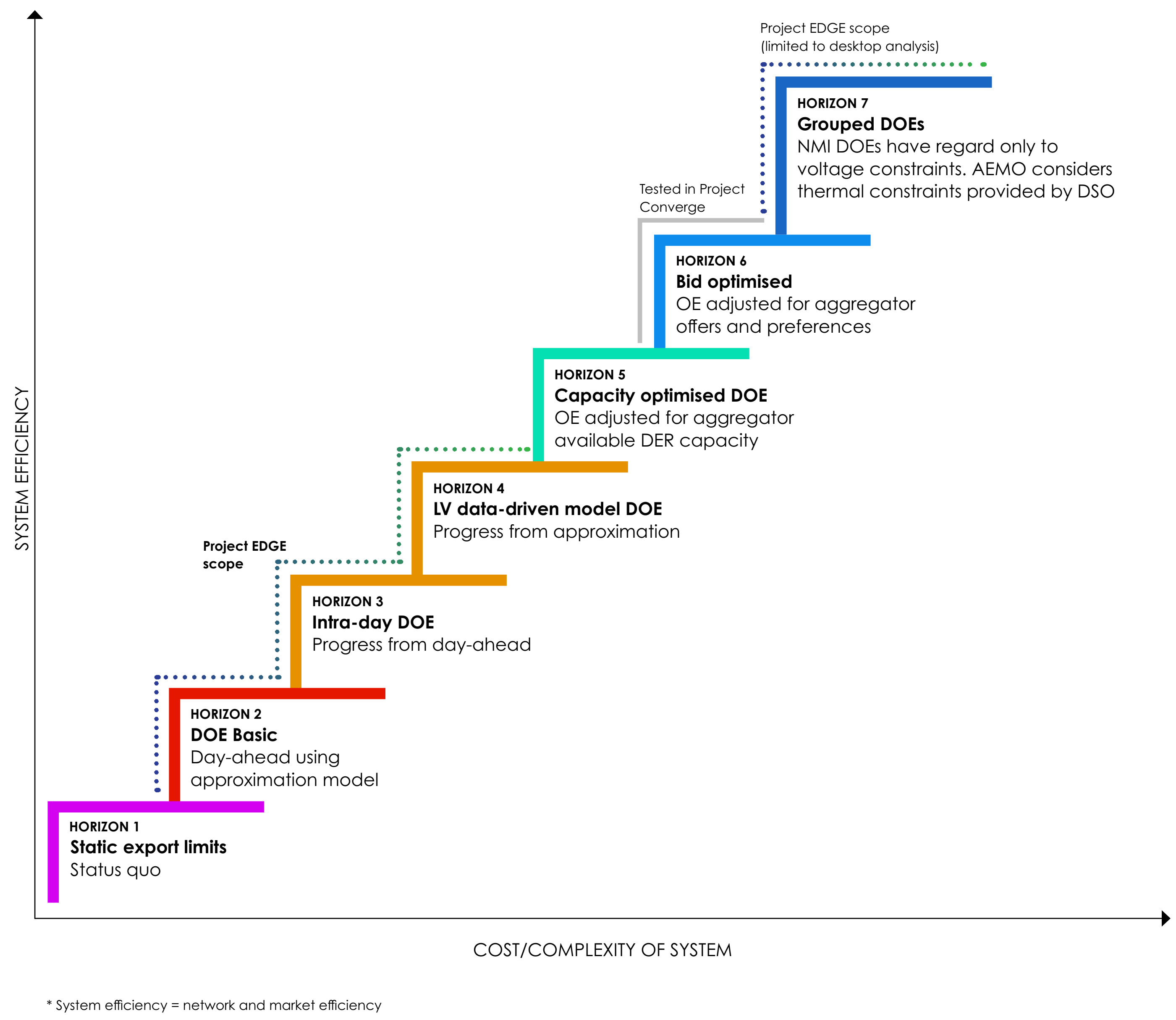
This section provides more context and detail on the key findings and insights outlined in the Context section of this chapter.

4.3.1 Impacts of DOE design

The design of DOEs has material impacts on network operation and efficient delivery of services

The calculation of DOEs can impact their efficacy and the extent to which spare hosting capacity is unlocked for flexible resources to use. However, there is a progression from simplicity to complexity in the calculation of DOEs that results in a spectrum of DOE efficacy: as DOE design becomes more complex, DOEs become increasingly more efficient in terms of improved hosting capacity. This spectrum of simplicity and efficiency is illustrated in Figure 31. It begins with basic DOEs sent to aggregators on a day ahead basis.

Figure 31 | Spectrum of the simplicity-efficiency trade-off for DOEs and wholesale dispatch



The spectrum illustrated has evolved from that initially developed at the beginning of Project EDGE and included in the Interim Report.[136] The changes made have been informed by the findings discussed in this chapter. Specifically:

- Separation of the LV network model and intra-day DOE (discussed in section 4.3.5). Intra-day DOEs could be achieved through simpler and less accurate calculation models. As discussed in section 4.2, other DNSPs may not be able to replicate directly the LV network model developed by UoM. However, this model does represent the more sophisticated end of the spectrum in DOE efficacy before progressing toward the concept of economically or bid optimised DOEs. As such, it is likely to provide more efficient DOEs but would be more complex to implement
- Inclusion of capacity optimised DOEs (discussed in section 4.3.6.2). Towards the end of the field trial, AusNet developed an alternative approach to optimising DOEs. Time limitations prevented an exhaustive analysis of this approach; however, initial findings indicate there could be merit in exploring this concept further

135 Gonçalves Givisiez A, Ochoa L, Liu M, Bassi V. Assessing the Pros and Cons of Different Operating Envelopes Implementations across Australia, CIRED 2023, Rome, Italy, June 2023. https://www.researchgate.net/publication/371686444_Assessing_the_Pros_and_Cons_of_Different_Operating_Envelopes_Implementations_Across_Australia

136 Project EDGE. 2022. Project EDGE: Public Interim Report Version 1 July 2022; section 5.1. https://arena.gov.au/assets/2022/07/project-edge-interim-public-project-report.pdf

- Bid optimised DOEs. These were initially referred to as economically optimised DOEs. However, due to certain limitations (discussed in section 4.3.6) the project pivoted to conducting theoretical desktop analysis to identify if there was value in further exploration of the concept.

4.3.2 **Fairness in DOE objective functions**

Maximising aggregate export is the objective function that most benefits all consumers

Customers that choose a dynamic connection agreement with their DNSP agree to receive DOEs during times of network congestion. For most of the year, DOEs could enable greater customer solar export (e.g. up to 10kW versus 5kW or lower with a static connection agreement), in exchange for less exports during congested periods.

A DOE objective function is used in the calculation of DOEs to allocate spare network hosting capacity among participating DER customers. Objective functions can produce different allocations among customers depending on the objective applied.

UoM's research for Project EDGE applied and compared different DOE objective functions over a range of representative networks, DER penetration levels and levels of DER participating in the market via VPPs.[137]

Three representative networks were modelled: regional, suburban and city. The DOE objective function study explored the network allocation capacity applied across a spectrum of objective function options. The analysis examined the technical, economic and fairness impacts of a DNSP using different DOE objective functions to allocate hosting capacity among customers.[138]

Fairness is a subjective term with different meanings to different people and with different financial outcomes for DER and non-DER consumers. A key issue when analysing the impacts of DOE objective functions is whether fairness should be measured by fairness only for consumers with DER and receiving a DOE, or fairness for all consumers with and without DER.

The Project EDGE hypothesis was that increasing network efficiency would likely be fairer for all consumers through reduced network and whole-of-system costs that translate to reduced electricity bills for all consumers, which aligns to the NEO's focus on the long-term interests of all consumers.

UoM found that maximising network utilisation could yield the highest net economic benefit for all consumers, in line with the NEO.[139] Therefore, the 'maximise export' DOE objective function should be considered the default as DOE design and policy is defined. This objective function considers fairness from a whole-of-system and consumer perspective, rather than the individual DER perspective.

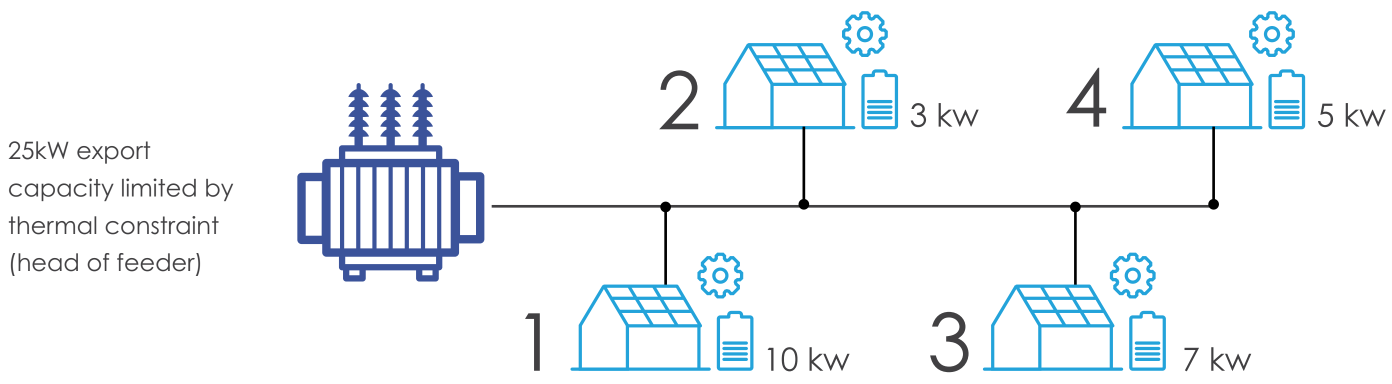
Figure 32 provides an illustrative example of a local distribution network area. The example network area has four houses with DER, with an aggregate DER export capacity of 25kW at the head of the feeder.

137 Project EDGE. 2023, Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne. https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

138 Project EDGE. 2023, Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne: https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-executive-summary.pdf?la=en

139 Project EDGE. 2023, Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne: https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

Figure 32 | Illustrative example of local distribution network area with export capacity limited by thermal constraint



Source: Project EDGE, Project EDGE Fairness in Dynamic Operating Envelope Objective Functions[140]

Figure 33 visualises the representative results from the study by applying the maximising aggregate export objective function to the illustrative example in Figure 32. The blue reflects allocated network hosting capacity while the green reflects unallocated capacity.

- The DER at the head of the feeder (house number 1, DER 1) are prioritised (10kW).
- House number 3, DER 3 at the end of the feeder, is allocated 6kW. However, because this house has a rated capacity of 7kW, it has spare DER capacity that is not utilised.
- House number 4, DER 4 at the end of the feeder, has a rated DER capacity of 5kW but is not allocated any network hosting capacity.
- The DER at the head of the feeder receives priority because of its physical proximity to the transformer.

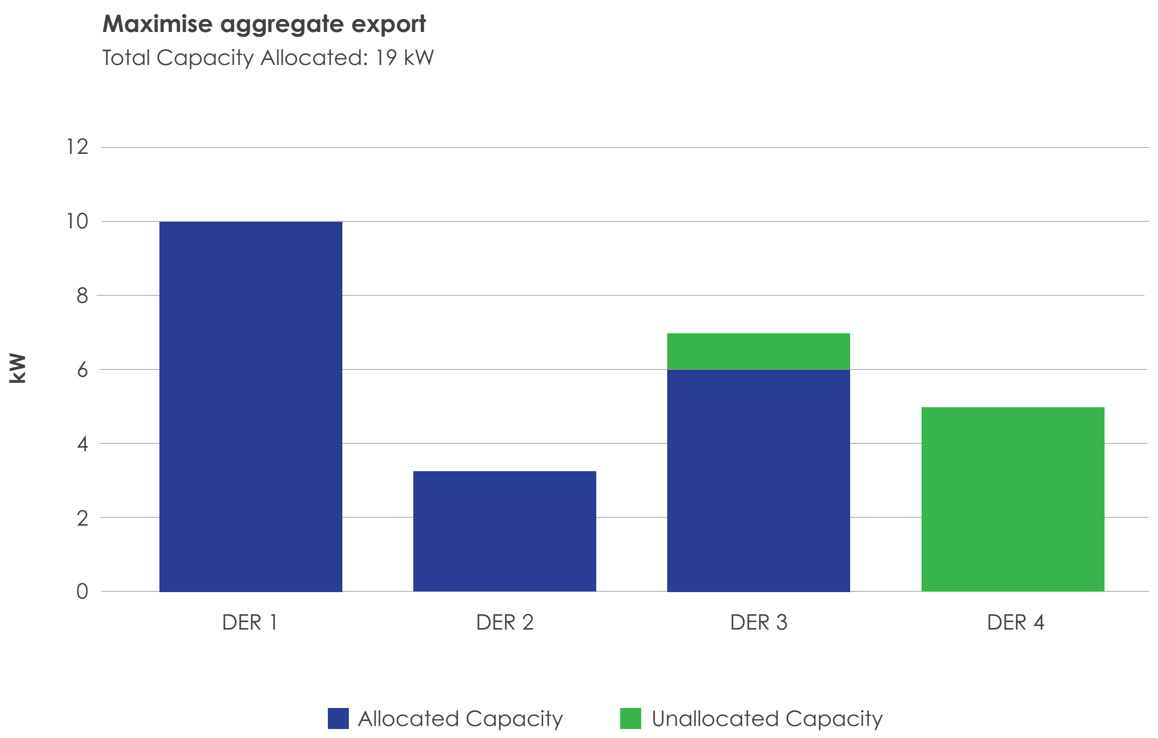
DEFINITION
Unallocated DER capacity

Unallocated DER capacity is a term used in the UoM's research and refers to the DER rated capacity that was prevented from exporting as it was not allocated network hosting capacity via DOEs.

Network physics mean that DER closer to the head of the feeder connection point are better able to export in full and therefore represent the most efficient allocation of spare network capacity.

140 Project EDGE. 2023, Project EDGE: Fairness in DOE Objective Functions Executive Summary Report, p.5. https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-executive-summary.pdf?la=en

Figure 33 | Illustrative example of how the maximise aggregate objective function would allocate capacity



Source: Project EDGE, Project EDGE Fairness in Dynamic Operating Envelope Objective Functions[141]

In the maximise aggregate export objective function, the total maximum network hosting capacity (19kW) that is allocated is the most out of all objective functions tested by UoM. But this may result in some participating customers having higher export capacity allocation than others for the duration of this constraint due to their location in the network.

At the other end of the spectrum, the absolute equal individual allocation objective function considers fairness by allocating the same network hosting capacity among DER customers even if they cannot use it. In a constrained network, it means the most constrained DER will determine the DOE that will apply to other DER even if the other DER may not be constrained. As a result, the total network hosting capacity allocated to the circuit will be lower than what it could be under the maximise aggregate export objective function.

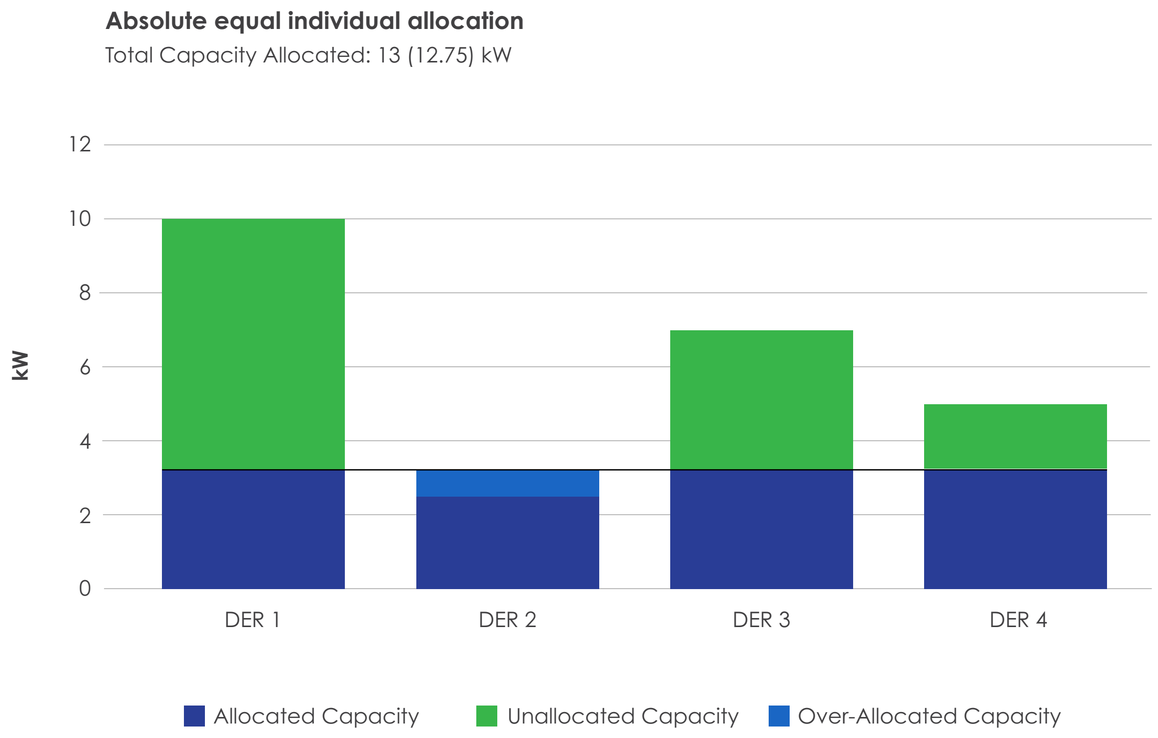
Figure 34 visualises the results from applying the absolute equal individual allocation objective function to the illustrative example in Figure 32.

- The black line represents the static export limit applied to all houses (3.25kW).
- The blue reflects the network capacity allocated through to flexible DER by the static limit.
- The green reflects the unallocated DER capacity.
- The static export limit means house 2 (DER 2) is over-allocated network hosting capacity (reflected by the purple) because it only has a rated DER capacity of 3kW.
- Meanwhile the other three houses, each of which has a DER rated capacity higher than the static export limit, have a proportion of their DER capacity left unallocated. The total capacity this objective function allocates (13kW) is greater than the total capacity that can be utilised (12.75kW).

UoM's analysis found the absolute equal individual allocation objective function could result in the lowest total aggregate export across the NEM. This would result in diminished benefit to non-DER consumers due to some allocation that cannot be used (where the DER of some distribution network customers are not large enough).

141 Project EDGE. 2023, Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne: https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

Figure 34 | Illustrative example of how the absolute equal individual allocation objective function would allocate capacity



Source: Project EDGE, Project EDGE Fairness in Dynamic Operating Envelope Objective Functions[142]

UoM found that, generally, calculating DOEs using concepts of fairness in relation to participating DER customers only (a subset of all electricity consumers) may reduce the technical and economic benefits that all consumers can obtain (via reduced electricity bill increases).

The impact is worse under higher DER participation and penetration levels because 'fair' allocations are limited by having to provide limits similar to the most constrained participating customer.

UoM's findings note that, currently, some static export limits may be highly conservative and in a high DER future, these static limits would need to be reduced further. UoM's research also examined how DOE efficacy changes with DER penetration and participation levels.[143]

Figure 35 shows how network capacity utilisation by DER changes with DER penetration and participation levels in the representative city network.

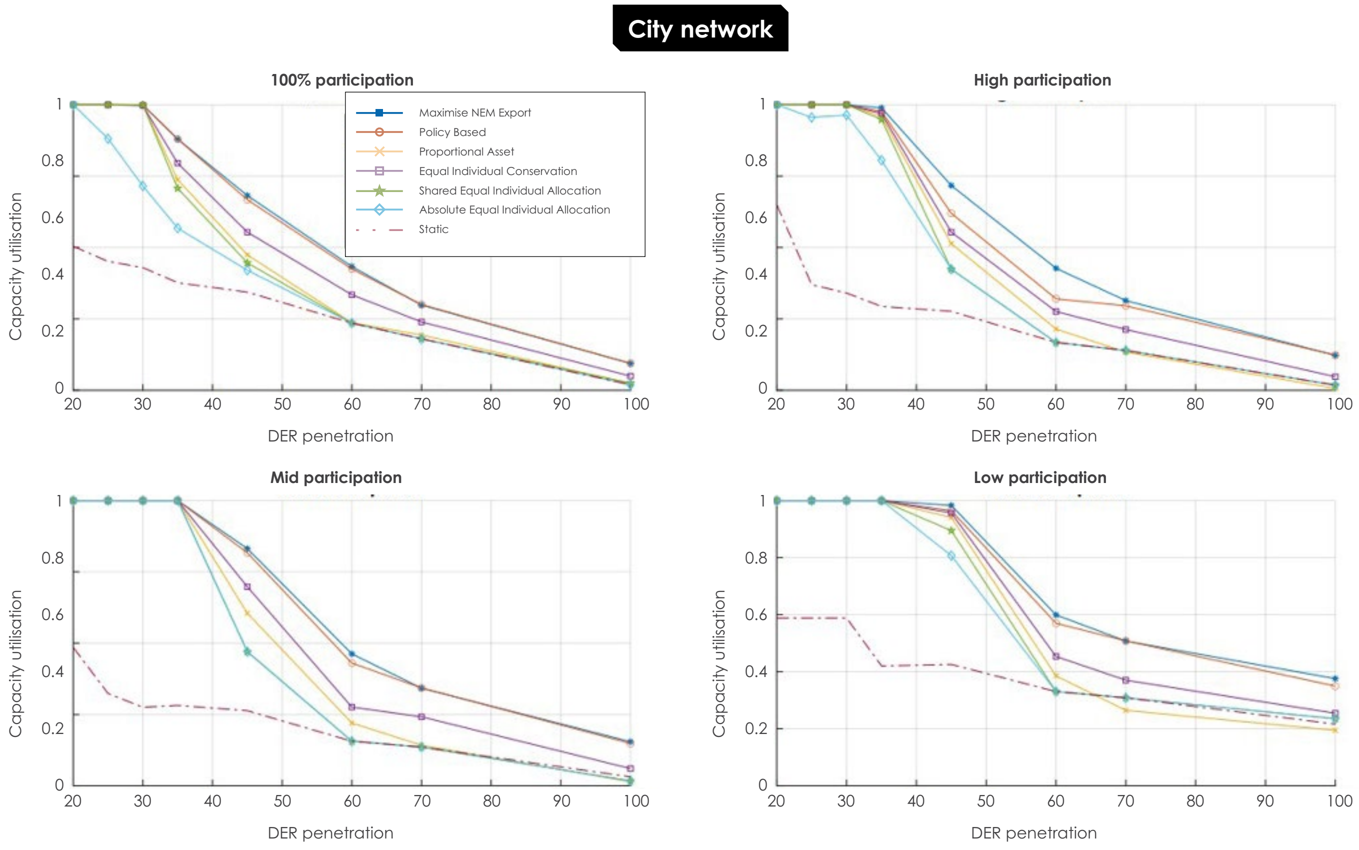
DEFINITION
DER participation

DER participation refers to active DER delivering electricity services, either wholesale or local NSS, through participating in a Virtual Power Plant.

142 Project EDGE. 2023, Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne: https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

143 Project EDGE. 2023, Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne, section 6-10. https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

Figure 35 | How different DOE objective functions could improve network capacity utilisation by DER in the representative city network with changing DER penetration and participation levels



Source: Project EDGE, Project EDGE Fairness in Dynamic Operating Envelope Objective Functions[144]

These results show that DOEs (regardless of objective function) immediately allow improved network hosting capacity utilisation by DER compared with static limits (the red dashed line).

Over time, the improved network hosting capacity utilisation decreases as DER penetration increases. This indicates that DOEs can unlock a lot of value by improving network hosting capacity utilisation by DER in the near term. However, over time as DER penetration increases, they would need to be reduced for all DER consumers that have DOEs.

There will be a point where traditional augmentation of the network will be required. This will occur where no spare network hosting capacity remains to be utilised by DER.

In networks where static limits would need to be reduced further in a high DER future, applying the flat access objective function could result in the lowest total aggregate export across the NEM. This would result in a diminished benefit to non-DER consumers due to some allocation that cannot be used (some DER customers' DER would not be large enough to use the full DOE allocated to them).

UoM's analysis focused on export limits. However, it found the DOE objective functions and assessment metrics are suitable for analysis of DOE import limits (noting there are complicating considerations relating to DOE import limits because DNSPs have an obligation to provide their customers with enough capacity to meet their essential load requirements).[145]

144 Project EDGE. 2023. Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne, p.40. https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

145 Project EDGE. 2023. Project EDGE: Fairness in Dynamic Operating Envelope Objective Functions – a report by the University of Melbourne, Appendix A. https://aemo.com.au/-/media/files/initiatives/der/2023/the-fairness-in-dynamic-operating-envelope-objectives-report.pdf?la=en

UoM's research found DOE objective function results for import limits were similar to those for export limits. However, it noted that a more detailed analysis and discussion on DOE import limits would be needed by industry to understand how they could be implemented in practice.

Various Project EDGE research activities point to an objective function that maximises aggregate export as being more efficient and providing benefits to all electricty consumers

Chapter 3 discusses the CBA's findings that increasing DER export could improve power system efficiency for all consumers. Enabling greater DER exports can allow lower cost DER to displace higher cost utility generation in wholesale markets.

The CBA's findings support UoM's findings that an objective function that maximises export and efficient allocation of network capacity will yield the highest net economic benefit for all consumers.

The Australian Energy Regulator (AER) is currently reviewing the NEM's regulatory framework for the implementation of flexible export limits.[146] The review seeks to ensure the existing regulatory frameworks for DNSPs provide effective 'guardrails' to support further rollout of flexible export limits in a way that protects and promotes the long-term interests of consumers. In terms of DOE (or flexible export limit) design, UoM's findings on the maximising aggregate export objective function align with the NEO's principle of promoting the long-term interests of all consumers.

UoM's findings on objective functions also align with consumer perceptions of DER export policy fairness (discussed in section 2.3.8). Deakin's research found that consumers perceive 'fair' policy as one that delivers the greatest benefits to their own household.[147] Consumers consider the personal costs and benefits of DER export policies when assessing the fairness of those policies. Ultimately, consumers want fairness applied to their own circumstances.

However, of the DER export policies explored in Deakin's research, the one deemed most fair involved no costly distribution network upgrades – which benefits all consumers – and included the application of DOEs, which benefits consumers with rooftop PV.

This indicates that a DER export policy that provides whole-of-system value and reduced costs, such as a policy underpinned by the maximising aggregate export objective function, may be perceived as 'fair' by most consumers since all households will benefit.

The challenge for industry and policy makers will be to ensure the narrative around DER export policies removes technical complexities and industry jargon and makes the benefits for all households – with or without rooftop PV – clear and easy to understand.

INSIGHTS

DOE objective function alignment to NEO

DOEs with the 'maximise aggregate exports' objective function of increasing system technical and economic efficiency, through allocation of spare network hosting capacity, are likely to provide the most benefits to all electricity consumers in the NEM and could be considered to maximise fairness from a whole-of-system perspective. This aligns to the principle of promoting the efficient operation and use of electricity services for the long-term interests of all consumers set out in the NEO.

There is potentially a method more aligned with the NEO than 'maximise aggregate exports'. Specifically, economic optimisation because it is based on price and as discussed in section 4.3.6.

Project EDGE identified there is potential value in this method, however, further exploration is needed to understand how it could be implemented to capture that value. This could potentially be achieved either within the DOE calculation, or through market mechanisms such as a secondary market.

146 AER. 2022. Flexible Export Limits Issues Paper, p 2, Box 2. https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf

147 Project EDGE. 2022. Project EDGE: General Community Perceptions of Distributed Energy Resources, section 4.6. https://aemo.com.au/-/media/files/initiatives/der/2022/community-perceptions-of-der-and-aggregation-services.pdf?la=en

4.3.3 **DOE calculation approaches and technical efficacy at different DER penetration and participation levels**

UoM's techno-economic modelling found that more sophisticated DOE design can enable the network to host more DER and thereby improve the opportunities for DER participation to deliver electricity services.[148]

UoM compared the technical efficacy of the approximation algorithm and the LV network model for a range of DER penetration and participation levels in real-world networks.[149] The two calculation approaches were also tested in the field trial (see section 4.3.4).

As noted in section 4.2, the LV network model is a more sophisticated calculation methodology than the approximation algorithm. However, DNSPs may not have access to an LV model and obtaining and verifying such a model may be costly and time consuming.

The approximation algorithm was developed by AusNet to generate DOEs for networks where it does not have a validated LV network model. The algorithm does not require forecasts of the network state (active power, reactive power, voltage) to operate. Rather, it uses the historical four weeks of customer smart meter voltage and current data to determine the available hosting capacity per phase with a 98% confidence interval. It then uses historical four weeks customer voltage data to estimate the 99th percentile voltage profile of each active customer to allocate the network hosting capacity.[150]

The LV network model[151] requires the DNSP to input the forecast active and reactive power of non-participating customers (i.e. consumers not participating in a VPP) and voltage forecast of the head of feeder (the secondary side of the LV transformer).[152] The algorithm for this model relies on verified LV network impedances and topology to calculate the optimal allocation while ensuring network constraints are maintained.

Voltage constrained networks are the dominant and driving factor for network constraints

UoM's techno-economic modelling identified that, in general, for a 3-phase LV network that is voltage constrained, lost DER capacity can be divided into five stages when using the approximation algorithm rather than the LV network model. These stages are summarised in Figure 36.

DEFINITION
Lost DER capacity

Lost DER capacity refers to the difference in improved network hosting capacity between the two calculation approaches (the approximation model has 'lost DER capacity' compared to the LV network model).

148 Project EDGE. 2023, Project EDGE: Testing different DOE approaches at DRE penetration levels in real-world networks. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge--testing-different-doe-approaches-at-der-penetration-levels-in-realworld-networks--work.pdf?la=en

149 The representative networks modelled were a city and a suburban network. Eight different penetration scenarios were modelled, ranging from 20% to 100% to determine the number of DER in the network. Each penetration scenario was further divided into four participation scenarios – low, mid, high and 100% – to determine the number of DER actively participating.

150 The approximation algorithm relies on substantial amounts of historical data and could not be modelled directly for the future DER scenarios. However, a proxy was used that provided results capturing the general operation of the approximation algorithm.

151 The UoM report uses the term the 'basic DOE algorithm' when discussing the LV network model. This report uses the term 'LV network model' to align with the terminology familiar to the Project Participants.

152 The side of the transformer connected to the source is the primary side. The side connected to the load is the secondary side. The network capacity of each phase of an LV transformer is primarily governed by the voltage on the secondary side of the LV transformer. If there was no voltage constraint or other thermal constraint downstream, the hosting capacity of the LV transformer would be exactly the same as the rated capacity of the transformer.

Figure 36 | Stages for lost DER capacity in a voltage constrained 3-phase LV network

Stage 1
- Both the approximation algorithm and LV data-driven model allocate the same capacity because the system is unconstrained in both cases
- Expected loss in capacity allocation is 0

Stage 2
- The approximation algorithm becomes voltage constrained
- LV data-driven model does not become voltage constrained
- Loss in capacity allocation increases as DER penetration increases
- This is because the approximation algorithm reduces the amount of capacity it can allocate
- Meanwhile, the LV data-driven model still allocates full capacity

Stage 3
- The LV data-driven model begins to be voltage constrained
- However, the network is less heavily constrained in the LV data-driven model because it has only just become constrained and has more options to allocate additional capacity
- This means the lost DER capacity will continue to increase, albeit more slowly

Stage 4
- Once LV data-driven model hits thermal limits, the expected loss in capacity allocation reduces as the LV data-driven model is no longer able to increase the absolute capacity it is allocating
- Meanwhile, the approximation algorithm is still able to increase the absolute capacity it is allocating

Stage 5
- It is possible if the DER fleet is large enough (oversized), that the approximation algorithm could also reach the thermal capacity of the transformer
- Then, at this point, there is no difference between the approximation algorithm and the LV data-driven model
- This means lost DER capacity will remain constant

UoM's findings regarding the stages for lost DER capacity can be summarised as follows:

- Under low DER penetration and with no network constraints, there is minimal difference between the two calculation approaches.
- As DER penetration begins to increase, loss in capacity allocation increases for the approximation algorithm because it is less accurate. Meanwhile, the LV network model can continue to allocate full capacity because it is more accurate. At this point, the LV network model becomes more efficient.
- When DER penetration becomes material, the LV network model begins to become constrained. This provides the approximation algorithm time to catch up, and the difference in improved network hosting capacity between the two calculation approaches decreases.

The key insight is that, fundamentally, the more accurate LV network model provides more improved network hosting capacity throughout and, as such, it would be better to move to the more accurate approach sooner.

However, UoM notes the point at which the approximation algorithm begins to lose DER capacity allocation and the speed at which the loss increases depends on the physical network, the amount of DER in the network and the conservatism of the estimates of the network state.

Until the approximation algorithm begins constraining allocation capacity frequently, there may be little benefit in making the investment required to transition to the LV network model. Once the approximation algorithm begins becoming constrained, the lost DER capacity increases quickly as new DER are added to the network.

Based on its findings, UoM does not recommended that DNSPs wait on their transition to the LV network model for this to occur, as this would result in near constant network constraint events.

An increase in the severity or frequency of approximation algorithm capacity allocation being constrained should be a signal to DNSPs that they are potentially losing significant amounts of DER capacity by not transitioning to the LV network model, and the problem will only keep getting worse. Considerations for industry, taking into account all the evidence, are provided in section 4.4.

Adequate DOEs can be applied without the need for a full network model

As noted in section 4.2, the two models tested for Project EDGE may not be able to be replicated by other DNSPs since different networks have different available infrastructure and data that requires different implementation approaches. Nonetheless, the two models represent a spectrum of complexity and accuracy of DOEs:

- The LV network model represents the 'ideal' DOE in that it is the most advanced calculation and accurate approach.[153] But it requires a full electrical network model and full monitoring of the distribution network's customers. As such, it requires a more complex implementation.
- The approximation algorithm represents a simple approximation or estimation approach. IT requires limited monitoring, and its implementation is simpler. While it may not be as accurate as other approaches, it nonetheless helps to address network constraints. Its approach may be appropriate for DNSPs with less sophisticated infrastructure and data availability, and/or DNSPs seeking a simple and cost-effective approach if that meets their network needs.

The key insights from Project EDGE's findings are relevant to all DNSPs because they highlight that adequate DOEs can be applied without requiring a full network model and full network customer monitoring approaches.

Simpler approaches that can be calculated with limited infrastructure and data can provide value by improving network hosting capacity compared to static export limits. These approaches are also more easily implemented with current DNSP readiness. This means that DNSPs can start simply and, depending on their network needs, invest in capabilities over time to progress toward more accurate and complex DOE approaches.

In addition, not all DNSPs may need a more sophisticated and highly accurate calculation approach. There is diversity in the available infrastructure and data across DNSPs and, therefore, a single DOE calculation approach may not be possible or necessary.

153 Gonçalves Givisiez A, Ochoa L, Liu M, Bassi V. Assessing the Pros and Cons of Different Operating Envelopes Implementations across Australia, CIRED 2023, Rome, Italy, June 2023. https://www.researchgate.net/publication/371686444_Assessing_the_Pros_and_Cons_of_Different_Operating_Envelopes_Implementations_Across_Australia

4.3.4 Comparison of results for calculation approaches from field trial analysis and UoM's research

Analysis of field trial data (see section 5.2 for approach) was conducted to identify if there were similar findings to UoM's research on DOE efficacy. Specifically:

- The impact to DOE efficacy from different conservative assumptions in the calculation of the DOE (section 4.3.4.1)
- The impact of DOE efficacy on an aggregator's ability to provide services (section 4.3.4.2) – namely, whether a more accurate DOE (the perfect hindsight DOE) led to unused network capacity (i.e. the aggregator would not have used the more accurate DOE allocated to it) or whether it led to under-utilised DER (i.e. even with a more accurate DOE, the aggregator would still be constrained).

4.3.4.1 Conservative assumptions in DOE calculation: desktop analysis

Project EDGE tested the impact to DOE efficacy from different conservative assumptions in the calculation of DOEs. A desktop analysis of the field trial data sought to understand how close to the true network capacity DOEs could be set.

During the high-level design stage of Project EDGE, the project assumed the calculation of DOEs could be done in a way that economically optimised their capacity allocation among NMIs based on comparing aggregators' bids. However, through detailed design it became apparent that aggregator bids supplied at a whole-of-fleet-level (DUID) would not provide the granularity of information required for NMI-level DOE calculations.

Alternative models where aggregators supplied NMI-level bids were deemed costly for aggregators and would therefore have scalability challenges so were not pursued. Additionally, the use of pre-dispatch bids could carry the risk of potential gaming or anti-competitive behaviour if aggregators inflate their forecast DER capacity in an attempt to increase the DOE allocated to their sites.

Recognising that in theory DOE capacity could be economically optimised through either DNSP DOE calculations or independent market mechanisms (e.g. a secondary capacity allocation market), the project resolved to first test the maximum theoretical value that could be realised before determining the mechanisms to optimise. This analysis used a desktop study based on field trial data.

The analysis compared the eight permutations of DOE calculation methods and objective functions tested in the field trials (field trial DOEs) with theoretical DOEs referred to as 'perfect hindsight DOEs'. These perfect hindsight DOEs were generated using the DNSP DERMS system, after the fact with 100% knowledge of what happened on the network and what spare capacity remained.

Both LV network model and approximation algorithm perfect hindsight models are characterised by inputs that are actual voltage and current data readings. A perfect hindsight DOE defines the maximum power that could be theoretically dispatched without compromising the stability of the distribution network.

The approach for the analysis was:

- Calculate the perfect hindsight DOEs
- Use field test data from when each of the eight DOE permutations were issued to aggregators, and compare the field trial DOEs against the perfect hindsight DOEs.

For clarity, the eight permutations of DOE calculation methods and objective functions were tested in the field trial. As such, each permutation had field trial aggregator performance data available (data related to how aggregators behaved and performed under each of the field trial DOEs). This means the theoretical element of this desktop analysis is the calculation of the perfect hindsight DOE and the rest is field trial data.

The eight DOE permutations explored by Project EDGE are outlined in the table below

Table 3: DOE calculation designs used in the Project EDGE field trial

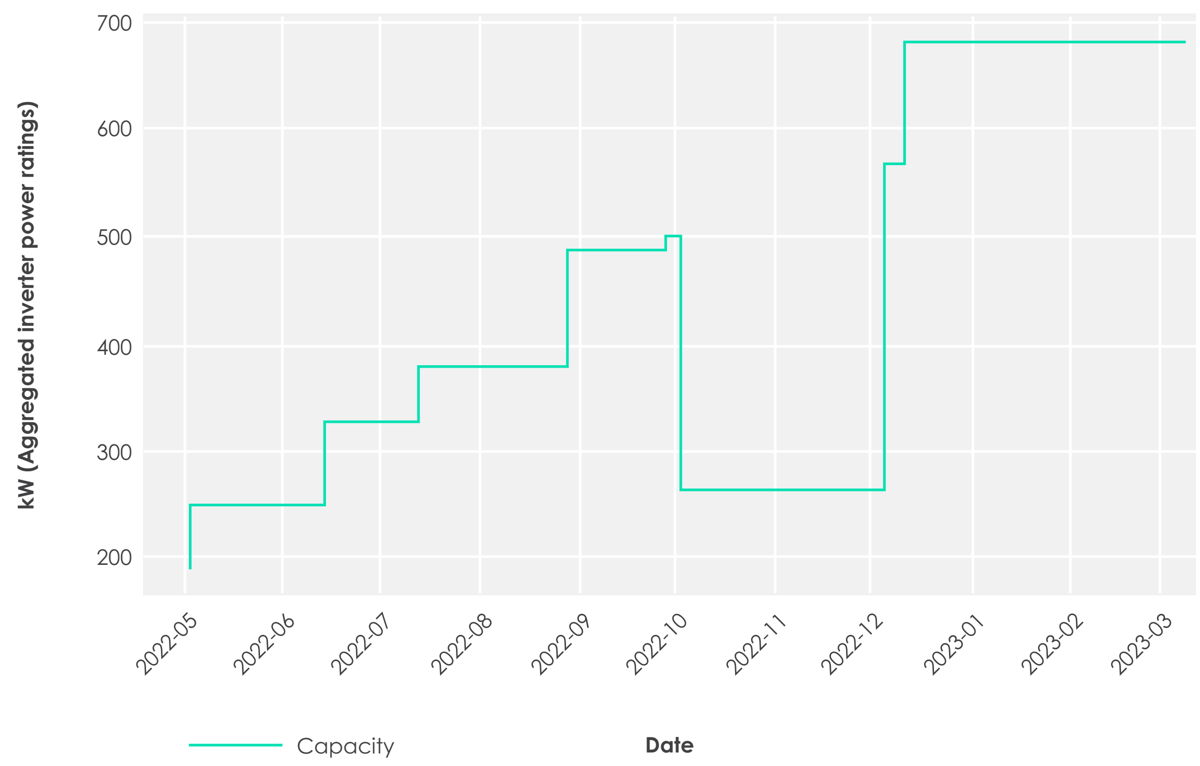
Permutation	Calculation frequency	Calculation method	Objective function
1	Day ahead	Approximation algorithm (referred to as 'approx.' in the field tests)	Equal allocation
2	Day ahead	LV network model (referred to a 'network' in the field tests)	Equal allocation
3	Day ahead	LV network model	Maximise aggregate service (the equivalent to the maximise aggregate export, but applies to both export and import, hence the use of the term 'service').
4	Day ahead	Combination of the LV network model and the approximation algorithm	Equal allocation
5	Day ahead	Combination of the LV network model and the approximation algorithm	Maximise aggregate service
6	Intra-day	Approximation algorithm	Equal allocation
7	Intra-day	Combination of the LV network model and the approximation algorithm	Equal allocation
8	Intra-day	Combination of the LV network model and the approximation algorithm	Maximise aggregate service

For Project EDGE, ~90% of customer DOEs were calculated using the approximation algorithm network and ~10% of customer DOEs were calculated using the LV network model due to the cost, effort and application feasibility[154] associated with the latter. Both approaches were used for the full duration of the field trial. Accordingly, the results discussed in this section should be read in the context that there was more data for the approximation algorithm-based field trial DOEs compared with the LV network-based field trial DOEs.

Each of the field trials ran for varying time periods, and the different fleet sizes increased in capacity as the trial progressed. This increase in aggregator fleet capacity size over time meant it was important to normalise the data to ensure the comparison was valid.

This increase in assigned network export capacity using the LV network model approach over time is shown in Figure 37. The reduction in capacity was not from customers leaving the trial; rather, it was due to some customers transitioning to approximation-based DOEs for a period of two months while their customer agreements were updated. These customers were still actively participating and being dispatched in the field trials.

Figure 37 | Increase in capacity for the perfect hindsight DOE produced ex-post growth over the field trial duration



The desktop analysis focused on the DOE export limits and involved the creation of a normalised load duration curve. Each curve was then reflected against the perfect hindsight DOE, as shown in Figure 38.

154 The LV network model relies on allocating between local NMIs and AusNet-only network-modelled clusters of NMIs when they occurred. In the trial; most NMIs were not close enough to each other to make the LV network model applicable. This is because most active customers had a 1:1 relationship with their supply substation. Each supply substation (except on a single-wire earth return (SWER) network) would constitute one network model. This means there could be hundreds of models, which was not feasible within the project scope and timeline. Hence, the focus was on applying network models where there were a cluster of active customers (e.g. Site A in the field trial had 10 active customers).

Figure 38 | Normalised DOE export capacity duration curve via different test constructs

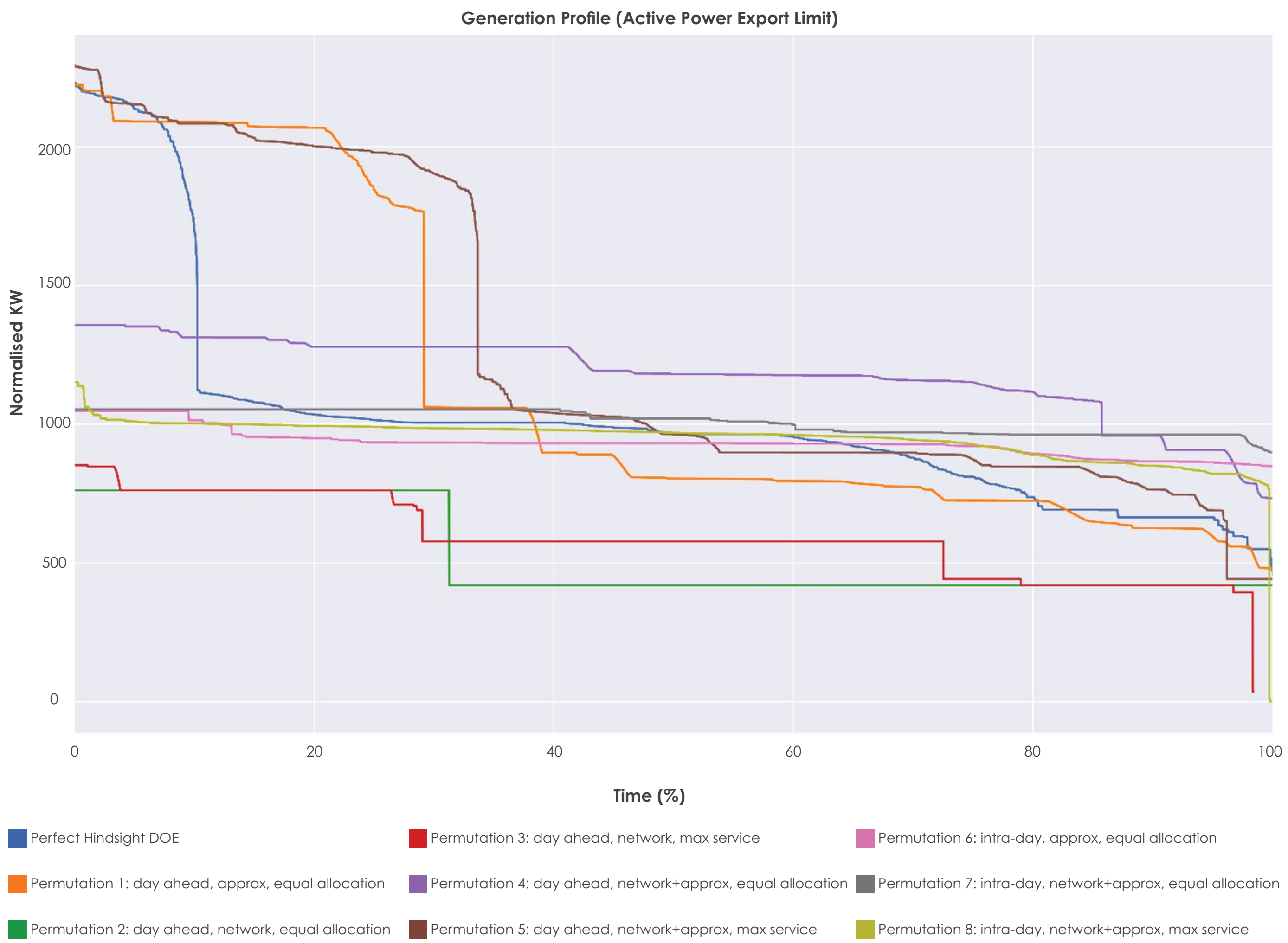


Figure 38 shows that the maximum energy release from the fleet of DER only occurred ~5% of the time. The shapes of each DOE trend have a pairing that can be attributed to the commonalities of each. It is important to note that some DOEs over-allocated capacity when compared to the perfect hindsight DOE (the blue line) at the extreme ends of the chart. This occurred less than 3% of the time.

Figure 39 highlights the normalised amount of energy (the area under each curve from Figure 38) released by each permutation of the DOE.

Figure 39 | Normalised capacity released via different permutations of the DOEs

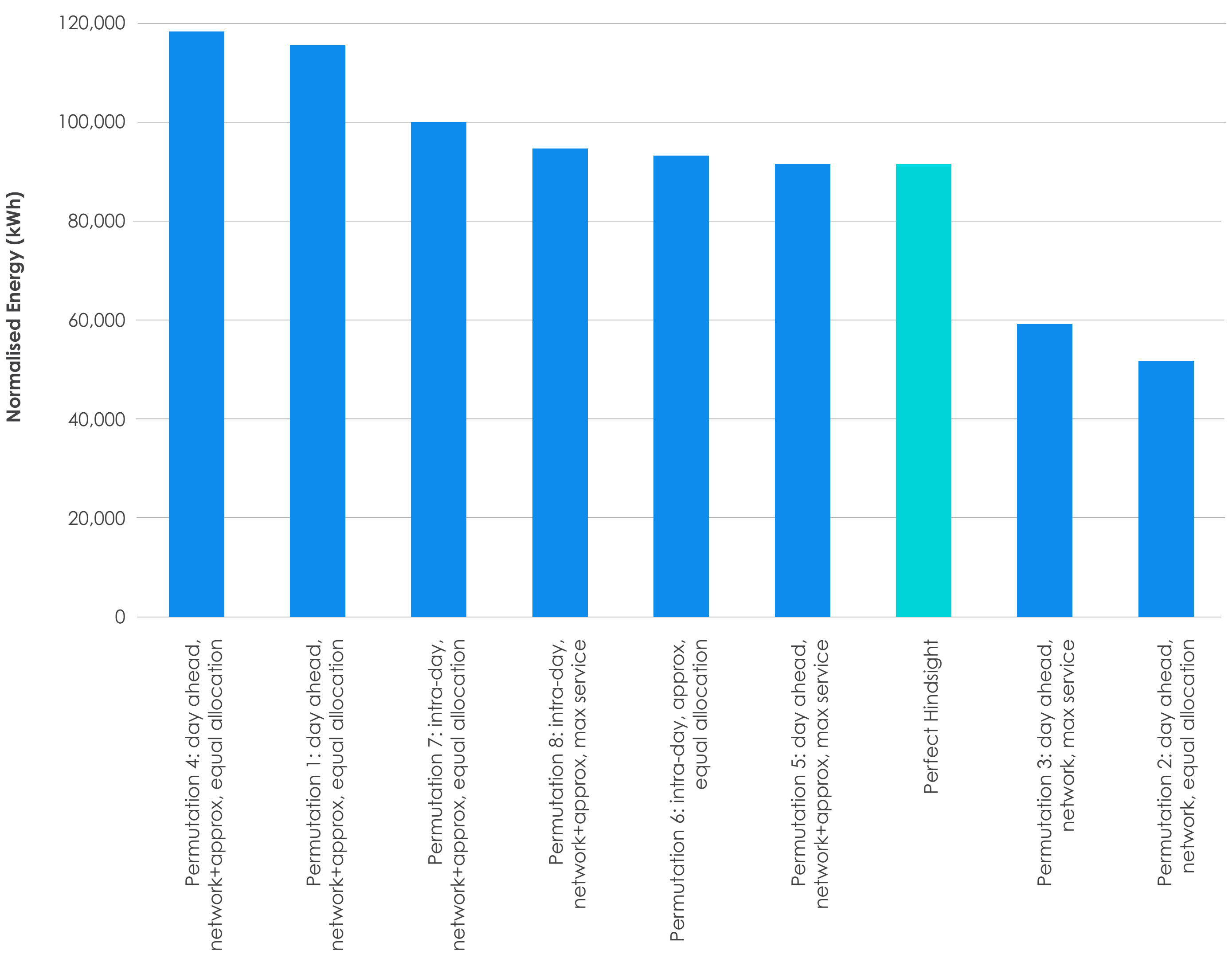


Figure 39 shows that when considering allocation methods (i.e. comparing the maximise aggregate service objective function against the equal allocation objective function within all similar remaining variables[155]), the 'highest' levels of export that occurred during the trial without consistently over-allocating all shared the maximise aggregate service objective function, and included at least some LV network model calculation in the DOE. See the bars to the right of the Perfect Hindsight bar. This supports the findings of the UoM both in terms of objective function and calculation approaches (discussed in sections 4.3.2 and 4.3.3 respectively).

UoM found that at low DER participation levels, both calculation approaches provide similar value. As DER participation levels increase, DOEs calculated using the LV network model are more accurate and enable the allocation of more spare network capacity compared to the approximation algorithm method.

DOEs calculated using the approximation algorithm in the field trial were the least accurate in allocating spare network capacity as they tended to over allocate beyond true network capacity (the perfect hindsight DOE). The approximation algorithm would need to be tuned and tested to ensure that over-allocation does not occur.

As previously discussed, because the approximation algorithm developed by AusNet relies on smart meter data, findings specific to the approximation algorithm cannot be generalised to all DNSPs, as some may not have material smart meter infrastructure in their networks. Accordingly, any simplified algorithms they develop will be different.

However, in terms of the Project EDGE insights that can be generalised, and based on the UoM findings (see section 4.3.3) and the CBA findings relating to the implementation of more sophisticated DOEs (see 3.3.1), there is merit in implementing a simpler algorithm and incrementally transitioning to more accurate calculation models when DER penetration justifies it.

This may be more cost efficient than a step change to more accurate, but more costly, DOE models for the whole network, and it would enable more improved network capacity utilisation over time compared to simpler algorithms.

The times when the field trial DOEs were higher than the perfect hindsight DOE was a result of forecasting error when the field trial DOEs were calculated. This is because:

- A perfect hindsight DOE uses real data after the event and therefore reflects the capacity that could have actually been allocated.
- The field trial DOEs are based on forecasts and are therefore subject to forecasting error.

In the case of the LV network model-only DOEs (represented by the green and red lines in 38), the reason they were consistently below the perfect hindsight DOE (blue line) is because of the imperfect day ahead forecasts used in these LV network model DOEs in conjunction with a 'buffer' for forecast error.

These forecasts can be improved but there was insufficient time within the project to do so. Nonetheless, while these DOEs were below the perfect hindsight DOEs, they were more technically efficient in terms of not over allocating network hosting capacity that would lead to DOE breaches (i.e. allocating more network capacity inaccurately that wasn't actually available).

The desktop analysis results did indicate intra-day DOEs provided greater consistent accuracy. This is likely due to how the system gained greater refresh of data (more frequency), which reduced the impact of longer-term forecast errors. In general, it is expected that near-term forecasting that relies on more recent data should improve forecasting.

UoM found the accuracy of head of feeder voltage forecasts are more influential on DOE efficacy than accurate non-participating customer load forecasts. See section 4.3.5 for a discussion on UoM's findings regarding the impacts of DOE frequency and forecasting accuracy on the efficacy of DOEs.

Desktop analysis also showed that day ahead field trial DOEs combining the LV network model and approximation algorithm over-allocated spare network hosting capacity compared to perfect hindsight DOEs. Since the perfect hindsight DOE is the DOE known to reflect the 'true' network limits, this indicates the approximation inputs of the calculation and the day ahead forecasts may have led to inaccurate forecasts.

The desktop analysis also showed that perfect hindsight export DOEs provided materially more aggregate spare capacity than field trial DOEs.

155 For example, permutation 3, day ahead, network, maximise service and permutation 2 day ahead, network, equal allocation.

INSIGHTS

Considerations for approaches to DOE calculation

LV network model approaches can be significantly more expensive to implement, but are more accurate compared with the approximation algorithm and allow for better utilisation of the network. The DOE efficacy of more accurate models increases as DER penetration grows.

However, there are cost benefit considerations for DNSPs when deciding whether to transition to more sophisticated models. While simpler models are not as accurate, they are cheaper.

The assessment of Project EDGE field trial data supports DNSPs starting with simple approximation-based DOEs to realise value quickly and investing incrementally in network monitoring and more sophisticated model-based DOEs over time, guided by localised DER penetration levels and network topologies.

As less accurate DOE calculation models perform worse than more accurate DOE calculation models when the network is constrained, DNSPs should consider transitioning to more sophisticated models once a less accurate model becomes constrained more frequently and severely,

To align with the regulatory economic framework for DNSP investment, this investment in DOE calculation models should be overseen by the AER to ensure it is prudent and efficient and in line with a network's DER penetration levels.

There could be a case for periodic analysis (as part of regulatory oversight) of DOEs against perfect hindsight DOEs (representing actual network limits) to make sure DER is not overly constrained beyond what is deemed appropriate.

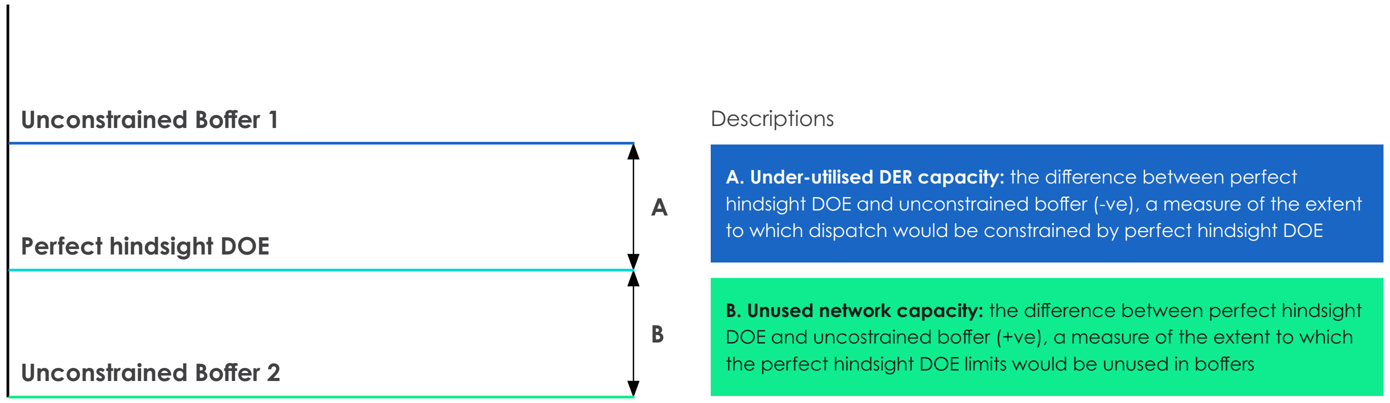
4.3.4.2 **Aggregator DOE capacity utilisation: desktop analysis**

The perfect hindsight DOEs discussed in the previous section were also used to calculate the amount of unused network capacity by one aggregator.

The aggregator provided individual site level unconstrained bids and offers for all sites in the field trial. That is, the aggregator provided a forecast on what it would generate if a DOE was not applied. This analysis of unconstrained bids and offers was applied to the corresponding perfect hindsight DOEs and was conducted over two months (February and March 2023).

The metrics definition of this analysis are shown in Figure 40.

Figure 40 | Definitions of under-utilised DER and unused network capacity



If the unconstrained bi-directional offer was greater than the perfect hindsight DOE (the difference represented by A), the DER would be constrained because the aggregator's portfolio had the ability to provide more generation/load than the DOE allowed (under-utilised DER).

If an unconstrained bid and offer was less than the perfect hindsight DOE (the difference represented by B), there would be more network capacity (unused network capacity) than could be utilised by the aggregator's DER portfolio.

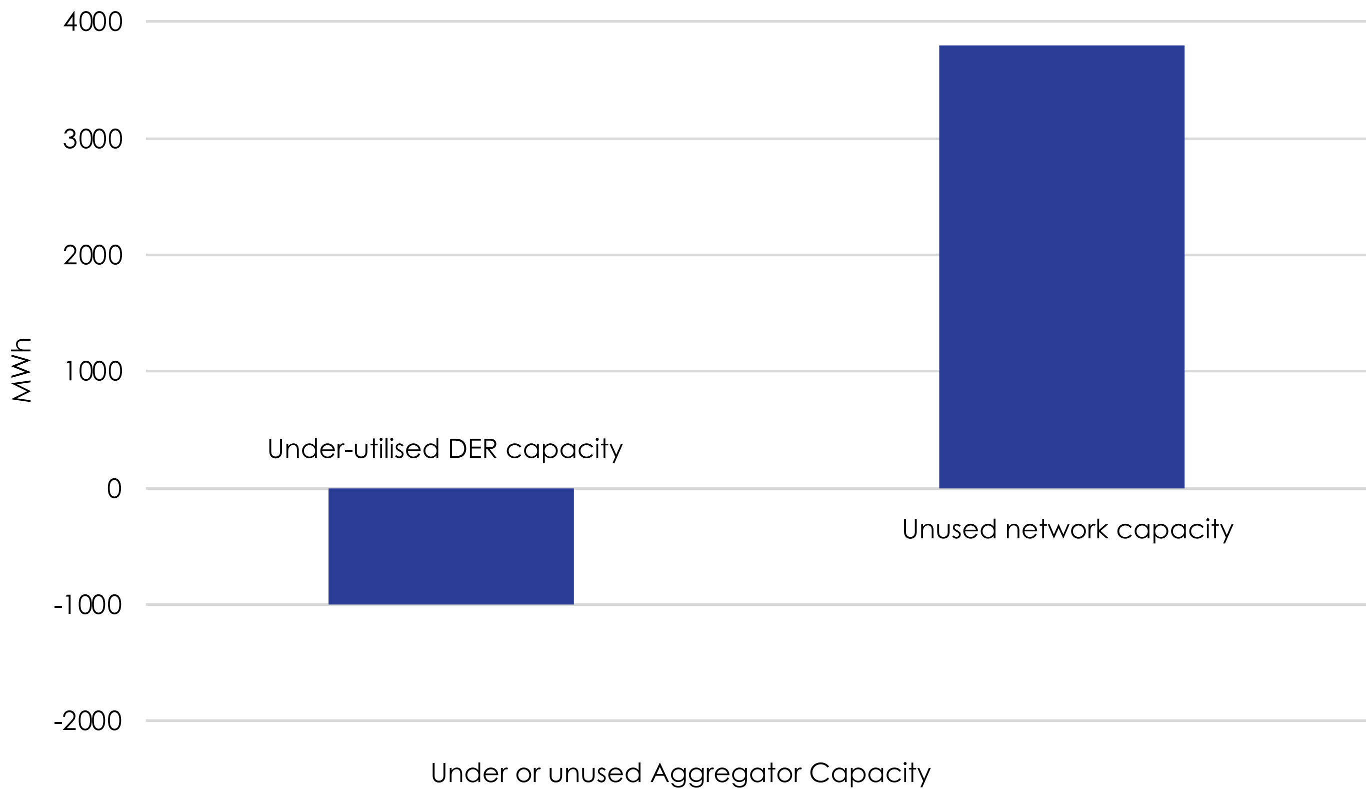
The summary for each site (n95) is shown in Figure 41 for a 'pseudo flex' perfect hindsight DOE (i.e. calculated for the desktop analysis as Flex DOEs were not field tested – see section 4.2 for an explanation of pseudo-Flex DOEs). Pseudo-Flex DOEs were used in this analysis to isolate the impact of the perfect hindsight DOE on DER.

Figure 41 | Comparison of the perfect hindsight DOE and unconstrained bids and offers of sites (n95)

The figure shows that some sites did not need any additional capacity allocated to them from the DOE (where the orange bars are lower than the blue bars). This resulted in unused network capacity.

Meanwhile, other sites were constrained (orange bars above blue bars) and, as such, were under-utilising their DER capacity, as there was spare capacity available for these sites but it was not able to be allocated under the perfect hindsight DOE. The results from Figure 41 were aggregated and are presented in Figure 42

Figure 42 | Total unused network capacity and under-utilised DER capacity for 1st February 2023 to March 2023 (n95) (desktop analysis)



This analysis showed that for this aggregator, there was materially greater unused network capacity allocated to it than the volume of underutilised DER capacity in its portfolio over the test period. This highlights that there is potential value in underutilised network capacity that could unlock greater DER participation if re-allocated.

Re-allocating spare capacity would require the aggregator (on behalf of its customer sites) to 'return' this unused capacity to the DNSP for redistribution to other sites. This could be a simple reallocation within one aggregator portfolio (see section 4.3.6.1) or it could be economically optimised through either DNSP DOE calculations or independent market mechanisms (e.g. a secondary capacity allocation market).[156]

Due to non-linearities in LV networks, further assessment would be required to understand how much more energy could be released for a given network area in practice. While further research is recommended, this Project EDGE analysis found ~1GWh of under-utilised DER capacity and almost 4GWh of unused network capacity over the two month analysis window.

156 This could be similar in concept to the Pipeline Capacity Trading operated by AEMO that applies to gas transportation services (gas transmission pipeline and compression services) outside of the Victorian Declared Transmission Service. It allows participants to trade spare gas pipeline capacity.
AEMO. N.d. About Pipeline Capacity Trading (PCT). https://aemo.com.au/en/energy-systems/gas/pipeline-capacity-trading-pct/about-pct.

INSIGHTS
Considerations for reallocation of unused network capacity

Analysis suggests that when DER participation is at greater scale, and DOEs are leading to greater levels of curtailment, there appears to be economic value and as such there is merit in exploring the reallocation of unused network capacity further.

4.3.5 The relationship between forecasting accuracy and DOE efficacy and resulting technical and economic impacts

Reducing uncertainty in calculating DOEs can improve the technical and economic outcomes

The UoM research notes that any deviation from the optimal capacity allocation (that is, allocated by DOEs using 'perfect knowledge' – see the perfect hindsight DOEs desktop analysis discussed in section 4.3.1) has negative implications.[157]

Under lower active DER participation levels in a generally constrained network, there is greater uncertainty around the power flows of non-participating customers. This uncertainty causes much larger deviations in aggregate capacity allocated in the network.

In a constrained network, the higher the DER participation in VPPs, the less uncertainty there is in the total passive customer power flow. This leads to DOEs having reduced errors because the power flow of non-participating customers is a large source of forecast uncertainty. This is because active DER (DER participating in a VPP) get a DOE that defines the import and export limit.

The DOE is calculated assuming all active customers are either exporting or importing up to the limits. As such, there is no forecasting associated with these VPPs. As VPPs increase, there is less forecasting undertaken and any error of forecasting has less and less impact on DOE accuracy. Nonetheless, error from voltage forecasting remains.

INSIGHTS
Broad DOE customer coverage can increase network efficiency

The UoM findings indicate that higher DER participation in VPPs and broad DOE customer coverage can increase network efficiency (through improved network capacity utilisation from more accurate DOEs).

This is also supported by the CBA (section 3.1), which found there is a commercial case for as wide coverage of DOEs as possible to unlock greater spare network hosting capacity for DER consumers, which would increase value to all consumers

157 Project EDGE. 2023. Project EDGE: Determining the impact of update frequency on operating envelope efficacy. p.24. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-determining-the-impact-of-update-frequency-on-operating-envelope-efficacy--workstream-3.pdf?la=en

CASE STUDIES
DOE conformance and devices under alternative control

Although not specifically tested in the Project EDGE field tests, some aggregators conformed to a DOE without having operational control of all flexible devices at the premises. This led to the aggregator installing their own control equipment (a control relay) to switch off the third-party control equipment at the sites so that these 'other' devices did not lead to the aggregator breaching the DOE.

This demonstrates how this arrangement could potentially unnecessarily constrain consumer DER. This is particularly relevant for Queensland (where DNSPs commonly operate controlled load) and has broader application for sites where more than one aggregator is operating DER (for example, a PV aggregator and a hot water aggregator).

This also highlights the potential need for a 'lead aggregator' to make sure that customer preferences are being met between multiple aggregators. This would help to ensure that the site DOE is not breached and network capacity is used efficiently.

4.3.5.1 Frequency of DOE recalculation

DOE calculations are based on forecast information about the local network state. In terms of frequency of DOE recalculation, in general, the closer to real-time a forecast is generated, the more accurate it (and the DOE) are likely to be. However, more frequent forecasts and updates to DOEs will come with associated technical and economic implications for the DNSP.

The UoM techno-economic modelling found that the intra-day forecast only marginally improves the accuracy of customer load forecasting. This forecast is still substantially different from the 'true value' (i.e. a perfect hindsight calculation).

In its analysis of intra-day DOEs using the LV network model, UoM found there may be little benefit from implementing intra-day forecasts. This was supported by the desktop analysis (see section 4.3.4.1) which did not indicate that an intra-day DOE provided additional material value compared to a day ahead DOE. Rather, the desktop analysis indicated some day ahead DOEs with the same calculation approach and objective function as the intra-day DOE (as deployed in the field trials) enabled additional spare export capacity a greater proportion of the time.

However, these results would depend on how the intra-day forecast is implemented, compared with the day-ahead forecast (i.e. if a different model was used). With regard to AusNet's DERMS, there was no significant difference in the methodology.

If an intra-day forecast is able to provide a significant improvement on head of feeder voltage forecasts, then it could substantially reduce the severity of network constraint violations and under-allocation of capacity. As found in the UoM research, the accuracy of head of feeder voltage forecasts is more influential on DOE efficacy than accurate non-participating customer load forecasts.

This finding means if intra-day forecasts could be shown to improve head of feeder voltage forecast accuracy, then DNSPs could consider it worthwhile to deliver intra-day DOE updates.

UoM's analysis was in relation to the LV network model. The approximation algorithm developed by AusNet did not use near real-time data; however, it could in theory. Intra-day forecasts would essentially require a change in how often the forecast is run, and an approximation model could be built to perform in such a way.

To achieve improved head of feeder voltage forecast accuracy, DNSPs would require enhanced monitoring equipment at LV transformers to run a level of state estimation that provides a reliable and consistent view of the electrical state of the network and can be run at frequent enough intervals (see the GridQube case study in section 4.3.7.5, which discusses the use of a state estimation approach).

Project EDGE tested day-ahead DOEs and 6-hour frequency DOEs in the field trials. The results indicated a DOE calculation frequency less than 6 hours ahead may not be feasible in the near-term. This was because material updates to forecasts could not be obtained in less time.

Forecasts are generated using historic data inputs. The more frequently a forecast is generated, the more frequently historic data would need to be input. Project EDGE found that while the average update time for smart meter power quality data is one hour, some sites can take up to four hours due to unstable communication links. Improving smart meter communication is possible but could come at significant cost. For these reasons, the project implemented a six-hour intra-day DOE.

The head of feeder voltage could be updated more frequently than smart meter power quality data. As this has a greater impact on DOE accuracy, it may be an option to investigate different update frequencies for head of feeder voltage forecasts.

INSIGHTS

Maximising the utility of DOEs through forecasting the head of feeder voltages

To maximise the utility of DOEs, future focus should be on forecasting the head of feeder voltages.

4.3.5.2 Technical and economic implications of inaccurate DOEs or DOE breaches

In different circumstances, inefficient DOEs can lead to both an over-allocation of capacity to coordinated DER (potentially breaching network limits) and an under-allocation of capacity to coordinated DER (which can unnecessarily constrain DER).

The hypothetical impacts of breaching network limits through an over-allocation of capacity were identified in discussions with DNSPs and AEMO. Key impacts are outlined in the table below.

Table 4: Key hypothetical impacts of DOE breaches

Impacted party	Impact
DNSPs	If unmitigated, in the most severe scenario, DOE breaches could lead to unstable power quality. This could lead to: • Power failures • Damage to electricity equipment and reduction in life of the equipment • Increased distribution system losses • The need to oversize the network to mitigate impacts. These outcomes are therefore also detrimental to distribution network customers (see Customer row in this table). The technical impacts from DOE violations should not impact DNSPs if these risks are managed through accurate DOE calculations and effective conformance and compliance frameworks. DNSP curtailment triggers and protection mechanisms also protect against these risks. DNSPs rely on over-voltage setpoints in the DER inverter to trigger in an over-voltage scenario caused by too much export. For import, fuses would blow when too much energy is drawn. This means DOE breaches have a lower impact on the distribution network itself than on distribution network customers.
AEMO	As outlined above, unmitigated DOE breaches could lead to localised contingency events, such as blowing fuses on the distribution network and automated triggering of protection mechanisms. These protection mechanisms should also mitigate the risk of DOE breaches causing system-wide contingency events. That said, widespread breaches of DOEs, which at a local level are not sufficient to trigger protection mechanisms, could in aggregate breach network constraints upstream (potentially at transmission level). AEMO can manage these risks if distribution network limits provided at the distribution and transmission interfaces align with the bid quantities received from the aggregators so that Security Constrained Economic Dispatch is preserved (see section 8.3.4.3). This indicates the importance of DNSP, TNSP and AEMO coordination to prepare for these types of scenarios and of DOEs being shared with both AEMO and the TNSPs.
Customers	The primary impact of DOE breaches is on distribution network customers. DOE breaches can impact voltage levels, which gradually reduce the life of electrical and electronic equipment, and power quality (flickering lights). Additionally, voltage increases from DOE breaches will trigger curtailment of export in newer PV inverters with a power quality setting. The impact of this is a reduction in the use of the customer's PV and the export of neighbouring customers.

INSIGHTS

Customer impacts from DOE breaches

There would be detrimental customer impacts from DOE breaches (potentially caused by an over-allocation of capacity to coordinated DER). This indicates that industry and regulators should consider DNSP investment in more accurate DOE calculation capabilities as aligning with the NEO's objectives to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interest of electricity consumers.

Inaccurate DOEs can also lead to an under-allocation of capacity to coordinated DER. This can result in detrimental economic outcomes for the market (and adds cost to all consumers' electricity bills) by unnecessarily constraining the power flow from DER.

Under-allocation of network capacity also constrains the value that aggregators can obtain from the market and pass on to their customers, dampening the incentives to enrol in VPPs and consequently limiting the benefits available to all consumers.

The CBA noted that forecasting uncertainty could theoretically be reduced (and therefore DOE efficacy improved) through:

- More frequent calculation of DOEs – e.g. intra-day rather than day ahead
- Using a more accurate calculation methodology – e.g. LV network model versus approximation algorithm.

The CBA was modelled over a 20-year horizon and assumed forecast improvements are material. The findings regarding different DOE calculation approaches from UoM and desktop analysis of field trial data indicate intra-day DOEs may not provide sufficient additional material value to balance the operational costs of more frequent calculations.

However, UoM does note that improving head of feeder voltage forecasts could improve accuracy. Accordingly, the results from UoM and the desktop analysis of field trial data do not contradict the CBA, based on assumed material forecasting improvements on head of feeder voltages. This should be a focus area to unlock the value potential from intra-day DOEs identified by the CBA.

INSIGHTS

Unlocking the potential economic value of greater DOE efficacy

Improving head of feeder voltage forecasts will also assist in unlocking the potential economic value of greater DOE efficacy through more accurate forecasting, as identified by the CBA.

4.3.6 Alternative approaches to optimising DOEs

Project EDGE considered, but did not trial, alternative approaches to optimising DOEs from the spectrum of efficiency discussed in section 4.3.1. During the detailed design stage of Project EDGE, it became apparent that bid optimised DOEs were deemed too costly for aggregators and therefore would have scalability challenges[158]. Accordingly, the project pivoted to conduct a desktop analysis to understand the theoretical value that could be realised through optimised DOEs, comparing field tested DOEs with perfect hindsight DOEs and unconstrained aggregator bids.

Bid optimised DOEs are being tested in Project Converge through the concept of Shaped Operating Envelopes.[159] These DOEs prioritise allocation of distribution network capacity to sites with the lowest cost of energy. It is recommended industry further explore these concepts through the learnings of Project Converge.

This section discusses two approaches on the more complex but efficient end of the trade-off spectrum: Grouped DOEs, evaluated by UoM, and capacity optimised DOEs for which AusNet completed a desktop assessment.

4.3.6.1 Grouped DOEs

Grouped DOEs seek to leverage any ability to calculate DOEs in aggregate, rather than for individual NMIs.[160] The objective of Grouped DOEs is to allow DOE capacity to be exchanged between local resources. For example, if one site with DER is allocated more capacity than it can utilise and there is another site with DER nearby[161] that can use more capacity, the additional unutilised capacity can be re-allocated automatically to the DER that will use it.

UoM analysis found this approach could only be used to reallocate capacity for networks under thermal constraints due to the highly locational nature of network voltages.

In a simple network, when it is thermally constrained, Grouped DOEs can act to simultaneously reduce the cost of the aggregators' bid curve in the network and unlock additional capacity that would have remained unused under the LV network model.

However, UoM found that with increased DER generation in the network and distribution networks currently operating to boost distribution network voltages to accommodate demand, it is likely distribution networks will experience voltage constraints before thermal constraints for exports.

Given UoM's findings, the value of Grouped DOEs is likely to be marginal unless DNSPs mitigate voltage rise issues in the LV network using other means (see the discussion on voltage management services in section 7.1). In that instance, there could be value in using a grouped DOE approach to manage exports-related thermal constraints over the longer term.

UoM noted that for the use cases in its modelling, import capacity allocation was almost exclusively constrained by thermal capacity of the network. UoM noted it is likely Grouped DOEs could provide significant benefits (subject to the constraints discussed earlier in this chapter) for allocating DOE import capacity. This is because in the LV-data driven model, DOEs are unable to utilise flexible load diversity in allocating import capacity. Grouped DOEs have the ability to address this.

Another consideration for industry when deciding whether to move towards Grouped DOEs is an increase in amounts of flexible loads (such as batteries and EVs). The ability for import capacity to be re-allocated based on the aggregator bids re-introduces a level of load diversity into the import capacity allocation that could be key in delaying network reinforcement.

If industry considers there is value in moving towards Grouped DOEs, it should also consider a standards-based approach to moving in this direction. For example, the IEC 61968-5:2020 standard describes the functions and methods needed for the enterprise integration of DERMS functions, such as mapping DER group-level to device-level interactions for exchanges between DNSP DERMS and aggregator DERMS, and distribution management systems (DMSs).[162] The standard covers:

- How DER group-level commands are disseminated to downstream members
- How device-level status is aggregated into a group-level status and resource availability indicators.

The standard is intended to serve as the information model basis to enable group management through communication with devices across different protocols.

At this point, further technical and economic (CBA) assessments would need to be conducted to inform any decision on when and where to apply Grouped DOEs and how this would be implemented most efficiently.

4.3.6.2 Capacity optimised DOEs

In Project EDGE, the two DOE calculation approaches (LV network model and approximation algorithm) allocate available network capacity based on the DER nameplate capacity (DER rating).

The DER rating represents the maximum capacity that the DER may require. In practice, the DER capacity at a point in time is likely to be lower than the DER rating. For example, the export capacity may be lower than the DER rating when the solar generation is not at its peak due to cloud cover and/or the battery is not fully charged.

When the DER is allocated a DOE lower than its rating, it is not constrained by the DOE unless it has the capacity to exceed the DOE at that time instance. Conversely, DOE capacity not required at one NMI would result in unused network capacity (as discussed in section 4.3.4.2), reducing efficiency unless the unused DOE can be re-allocated to another NMI that requires that capacity. This is where capacity optimisation could be beneficial.

158 Project EDGE. 2022, Project EDGE: Public Interim Report, p 18. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports

159 DEIP. 2022, DER Market Integration Trials: Summary Report September 2022. https://arena.gov.au/assets/2022/09/der-market-integration-trials-summary-report.pdf

160 Project EDGE. 2023, Project EDGE: Testing different DOE approaches at DER penetration levels in real-world networks, Chapter 5. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge--testing-different-doe-approaches-at-der-penetration-levels-in-realworld-networks--work.pdf?la=en

161 The DER need to be in the same LV circuit and phase, and electrically close by to minimise distribution losses

162 International Electrotechnical Commission. N.d., IEC 61968-5:2020 Application integration at electric utilities – System Interfaces for distribution management – Part 5: Distributed energy. https://webstore.iec.ch/publication/60069

What is capacity optimisation?

In capacity optimisation the allocation of available network capacity through DOEs is based on DER capacity forecast from the aggregator rather than based on the DER rating. If the aggregator forecasts that its full DER rating is not available at a NMI, the DNSP could then re-allocate capacity to other NMIs with available DER capacity in the same local network area. The aggregator with available capacity would receive a capacity optimised DOE.

The hypothesis involved in capacity optimisation is that by calculating DOEs using actual import and export capacity available at a point in time, and not the maximum possible total import and export level, it could reduce wasted allocation and provide optimised DOE allocations to other customers who could use it.

Note that capacity optimisation is based on DER capacity forecast; that is, what the DER is capable of doing, and does not have any economic element to the allocation.

This is different to the economically optimised DOE approach (see section 4.3.4.1), in which network capacity is prioritised to the lowest cost energy based on bi-directional offers. Per the spectrum of efficiency/complexity for DOE design in section 4.3.1, the economically optimised approach is a progression beyond the capacity optimisation approach as it requires a higher level of DER participation to be effective (i.e. more than one VPP operating resources behind a constraint).

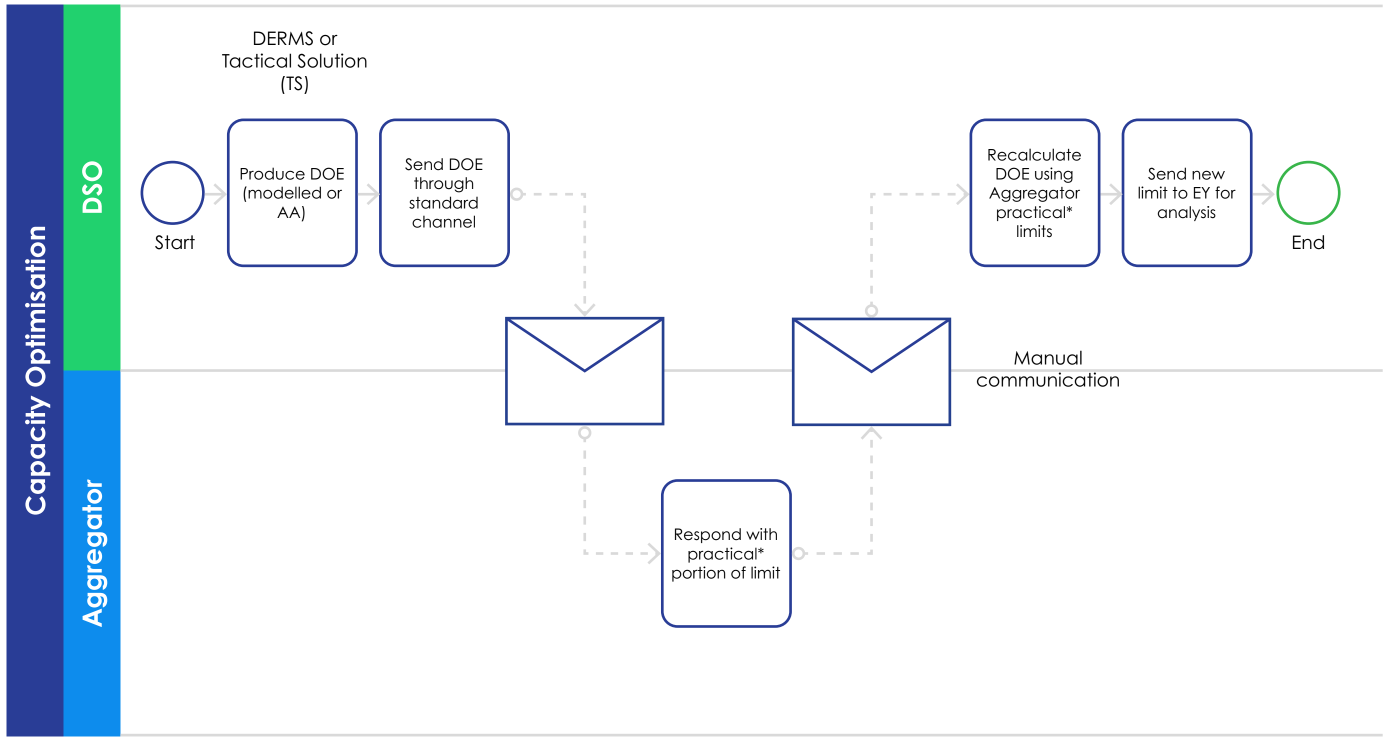
Because capacity optimisation removes wasted allocation from one NMI to provide it to others that can use it, and NMI DOEs are allocated based on network capacity in a local area, capacity optimisation only adds value when there is a cluster of NMIs effectively using the same network capacity. This generally means that the groups of NMIs are supplied from the same distribution transformer (multi-phase networks) or the same isolation transformer (SWER networks).

The capacity optimisation process

For the Project EDGE desktop assessment of capacity optimised DOEs, NMIs were grouped into clusters, with DOEs for each cluster calculated using UoM's DOE calculation method (LV network model). NMIs that were too remote from each other to significantly affect each other were not included in a cluster.

Figure 43 illustrates the capacity optimisation process used in the desktop assessment of Project EDGE.

Figure 43 | The capacity optimisation process



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*Practical limit = portion of the Aggregator's capacity that the Aggregator is prepared to use including:

1. Raw capacity
2. Reserved capacity for customer use
3. Reserved capacity for other uses or equipment limitations

Data from the aggregator was used to obtain the import and export capacities for each NMI for the desktop assessment. The pre-dispatch NMI-level bi-directional offer contains aggregator offers for 10 export and 10 import price bands. The highest export and import offers for an interval (bands 1 and 20) are taken as the maximum possible import or export capacity available at the time (MaxAvail).

Caveats in the process

In Project EDGE, DOEs were calculated in advance, either day-ahead or intraday (every 6 hours). This means that a DOE could be up to 6 hours old. Aggregator forecasts of DER capacity that are 6 hours old are found to be fairly inaccurate (see section 4.3), as aggregators have focused their efforts on refining their forecasts only for the time close to dispatch (under 2 hours).

Using the aggregator forecast DER capacity as the DOEs are generated (every 6 hours) for the desktop assessment will not reveal the true potential of capacity optimisation. Accordingly, the desktop assessment used aggregator DER forecast immediately preceding the dispatch time interval. These are the best forecasts available and are potentially more accurate than the likely forecasts that would be used if capacity optimised DOEs were calculated outside of a trial. Therefore, the desktop assessment results should be viewed as the best case result possible from capacity optimisation.

Effective capacity optimisation would rely on high levels of DER participation, DOEs being generated with high frequency (less than 6 hours) and aggregators maintaining accurate MaxAvail numbers in their bid file for each dispatch interval (representing their maximum capacity available for dispatch).

The time difference between frequency of DOEs and 5-minute dispatch intervals means capacity optimisation could be open to gaming. Aggregators could maintain high MaxAvail figures before the DOEs are generated, and then rebid lower MaxAvail capacities closer to gate closure. This would enable them to have maximum network capacity allocated to them in case they need it.

An economically optimised approach to DOEs could also carry a risk of gaming if aggregators submit low price bids before the DOEs are generated to maximise their allocation of network capacity, and then re-bid at higher prices before gate closure.

Minimising the time difference between the frequency of DOEs and 5-minute dispatch intervals, or using ex-post analysis to identify trends in this type of behaviour, could mitigate these risks for both approaches, but also carry higher costs for implementation.

A further drawback to both approaches is the requirement for NMI-level forecasts (or forecasts for resources at a granular location on the network) to be supplied to the DNSPs (which at scale would not typically be included in the bid file).

A potentially simpler implementation of capacity optimisation could involve aggregators indicating un-usable DOE capacity (for instance, where resources are out of service) by location to the DNSP. The DNSP could then recalculate the DOEs for that network area as part of their regular DOE updates to remove those sites identified by the aggregators and redistribute this among the remaining sites, until the aggregator updates their capacity again.

NMIs used in the capacity optimisation analysis

There were seven clusters in the Project EDGE trial (Cluster A to Cluster G) that have been modelled using the UoM network model based DOE algorithm. These sites vary in size from 1 to 10 NMIs in each.

Two clusters were selected for the capacity optimisation analysis, both among the largest clusters in the trial. The composition of the clusters is outlined in Table 5.

Table 5: Cluster used for the capacity optimisation analysis

	Size (NMIs)	Notes
A	10	Unconstrained network – Cluster A has a large capacity
C	6	Cluster C has a limited capacity – NMIs in this site are often constrained by the available network capacity

These NMIs were analysed across a week-long period from January 9 to January 15, 2023.

One aggregator participated in this activity, providing NMI-level bi-directional offers to serve as the forecast DER capacity.

Assessment criteria

The desktop assessment used the following criteria to compare the performance of capacity optimised and normal DOE approaches. The criteria measure the cluster performance where the active NMIs are connected, and are determined over the one-week period:

- Unused DOE allocation – the amount of energy (kWh) allocated to the site that is above what is required (and used) in the NMI-level bi-directional offer. The measure provides an indication of over allocation of DOE capacity
- Used DOE capacity - the total allocated capacity (kWh) that is used in the NMI-level bi-directional offer. This measure provides an indication of the potential benefit to the wholesale energy market, and is particularly relevant where the site is constrained.

In addition, to confirm if any particular NMI is worse off with capacity optimisation, the amount of energy (kWh) constrained at each NMI (from its available capacity) is measured over the period and compared with the normal DOE approach. The analysis results are presented below.

Table 6: Cluster used for the capacity optimisation analysis

Results for Cluster A – unconstrained cluster				
Findings – Used DOE capacity				
	Capacity optimised		Standard DOE	
	Export	Import	Export	Import
Required bi-directional offer capacity (kWh)	4,981.51	5,376.24	4,981.51	5,376.24
Required bi-directional offer capacity (kWh)	4,981.51	5,376.24	4,981.49	5,376.24
Unfulfilled bi-directional offer capacity (kWh)	0	0	0	0

The analysis above shows that for this unconstrained cluster, DOE capacity optimisation distributes network capacity to the DER as each requires and hence is fully utilised in the bi-directional offer (total unused DOE capacity is zero).

Unallocated network capacity is left for other DER as they come on-board in future. The standard DOE approach has over allocated network capacity based on DER rating (results in a positive total unused DOE capacity) and is therefore sub-optimal.

However, as the cluster is not constrained, there is little difference in the bi-directional offer quantities offered to the market so there is no practical advantage of applying capacity optimisation.

The assessment found that no NMIs were disadvantaged by capacity optimisation. No NMI had less capacity than they could use before or after optimisation.

Table 7: Results for Cluster C

Results for Cluster C – constrained cluster				
Findings – Unused DOE allocation				
	Capacity optimised		Standard DOE	
	Export	Import	Export	Import
Total DOE capacity allocated (kWh)	2,102.52	3,414.52	2,452.42	7,231.97
Total unused DOE capacity (kWh)	0	0	484.02	3,820.21
Findings – Used DOE allocation				
	Capacity optimised		Standard DOE	
	Export	Import	Export	Import
Required bi-directional offer capacity (kWh)	2,103.36	3,430.4	2,103.36	3,430.4
Bi-directional offer capacity allowed by DOE (kWh)	2,102.52	3,414.52	1,968.39	3,411.77
Unfulfilled bi-directional offer capacity (kWh)	0.84	15.88	134.96	18.63

The analysis above shows that for this constrained cluster, DOE capacity optimisation distributes network capacity to the DER as each requires and hence is fully utilised in the bi-directional offer (total unused DOE capacity is zero).

As the cluster is constrained, there was insufficient network capacity available to distribute across the NMIs and satisfy the desired capacity in the bi-directional offer in both DOE approaches. However, results showed a significant reduction in unused capacity with capacity optimisation, particularly for export constraints, which reduced from 135kWh to less than 1kWh across the week.

Of note in the unused DOE allocation findings, the total capacity allocated under capacity optimisation was less than that using standard DOEs. This desktop analysis was done based on typically accurate 5-minute ahead aggregator NMI-level forecasts, resulting in no unused capacity. As longer-term aggregator forecasts (over 2 hours) tend to be less accurate, a practical implementation of capacity optimisation should seek to ensure that, after all forecast DER needs are met, overallocations (within network limits) still occur to avoid aggregators breaching the tighter DOEs because of long-range forecasting error and to avoid aggregators being disincentivised to participate in future.

Key findings from the capacity optimisation analysis

As was expected, optimising an unconstrained cluster provided limited benefits.

The constrained cluster, however, experienced significant theoretical benefits from the capacity optimisation, showing that capacity optimisation could be a useful enhancement that can be applied to DOEs for clusters of NMIs, subject to the DNSP receiving accurate capacity forecast from the aggregator in a timely manner.

These findings are similar to the analysis discussed in section 4.3.4.2, which found there was economic value that could be captured, if DOEs are reallocated efficiently. With regard to capacity optimised DOE, this principle of economic value would apply to one aggregator.

INSIGHTS

Further investigation of capacity optimised DOEs is recommended

Further investigation of capacity optimised DOEs is recommended as part of a DOE design development roadmap, developed collaboratively by industry participants (see section 4.3.8).

4.3.7 DOE allocation point considerations

A key topic industry will need to resolve is whether DOEs should be applied to the NMI or at the level of flexible devices behind a meter, either individually or aggregated

A key decision industry will need to make is the location of the DOE application (the capacity allocation point). This has been identified as a future action in the AER's Issues Paper on the implementation of flexible export limits in the NEM.[163] The AER acknowledges the issues considered in the paper are a first step in what it anticipates will be an iterative process. The AER notes the issues considered are not intended to prevent further development of DOEs. The regulatory framework will need to continue to change and progress.

The AER notes a spectrum of options is available for DNSPs to adopt for capacity allocation. Two options were considered in Project EDGE:

- Allocation at the customer point of connection to the network (referred to as **Net NMI DOEs** in Project EDGE)
- Allocation only to controllable generation and load (referred to as **Flex DOEs** in Project EDGE).

A Net NMI DOE applies to all controllable and uncontrollable devices and is applied at the net connection point (the customer's NMI).

A Flex DOE applies only to the flexible device or devices (for example, it could apply to the aggregation of all flexible devices at a site or to each flexible device separately if there are different aggregators managing different devices at a single site).

Effectively, a Flex DOE describes the same constraint as a Net NMI DOE (i.e. the network limit does not change). However, under Flex DOEs, the uncontrolled element is removed. Remaining is the spare network hosting capacity that could be allocated to an aggregator for the operation of the flexible DER devices.

Figure 44 provides an illustrative example of the two different DOE allocation point approaches at a site with multiple aggregators.

Net NMI DOE: The DOE allocation point is the NMI (the network meter in the small purple box). The DOE applies to the site and therefore to all devices (1-5) in the larger purple box.

Flex DOE: Assuming a complex case in which each controllable device (1, 2 and 3) is managed by a different aggregator, the DNSP would provide each aggregator (blue, turquoise, and yellow) with its own Flex DOE, such as a new connection point.

If devices 1, 2 and 3 are managed by a single aggregator, the Flex DOE would apply to the aggregate of these devices. This DOE would be independent of the uncontrolled legacy rooftop PV (device 4) and the uncontrolled load (devices in 5).

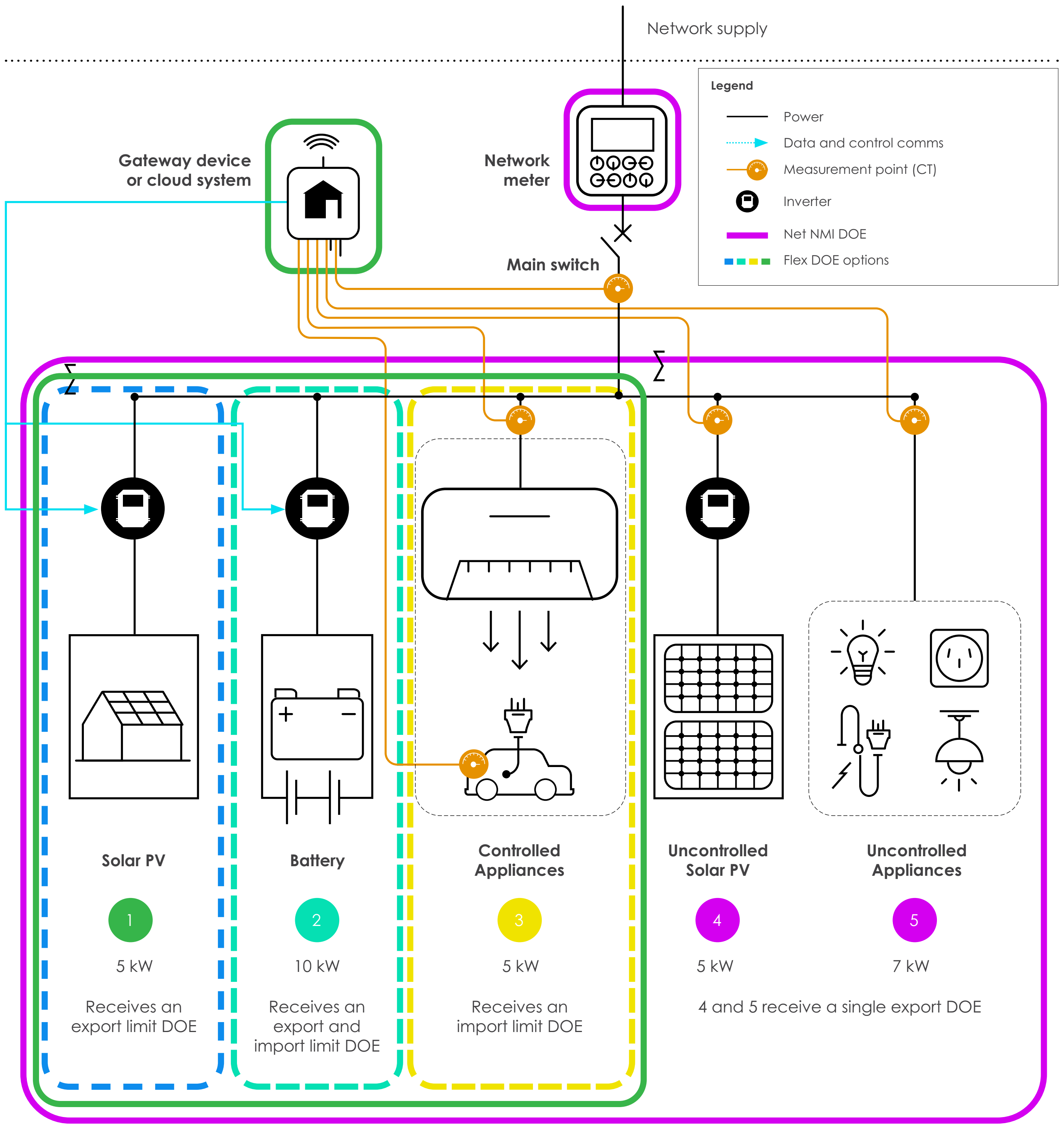
Key elements to consider in applying either of these approaches are:

- VPP operational risk
- Forecasting of uncontrolled load (highly accurate forecasting of uncontrolled load at individual customer sites is very difficult).

These are discussed below.

163 AER. 2022. Flexible Export Limits: Issues Paper October 2022, p 45, section 5. https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf.

Figure 44 | Illustration of the different DOE allocation point approaches



Note: Devices 1, 2, and 3 could also all be in the same DOE

4.3.7.1 VPP operational risk

In its deliberations over DOE allocation point, industry will need to consider which industry actor would be best placed to manage the operational risk of DOE breaches due to the forecast of uncontrolled load and generation informing the DOE not being conservative enough.

From a DNSP perspective, calculating a Flex DOE could require it to bear more risk (associated with forecasting uncertainty and potentially providing a limit that wasn't accurate enough) than calculating Net NMI DOEs, and therefore having to include a conservative buffer in the forecasting approach.

For an aggregator, the operational DOE conformance risk profile is theoretically lower under a Flex DOE (see section 5.3.2.6 for further discussion on the DOE breach analysis conducted).

If a Net NMI DOE applies, the aggregator needs to monitor uncontrolled resources and use controlled resources to keep connection point flows within limits.

With a Flex DOE, the aggregator is only responsible to maintain the flexible devices under its control within the given limits, although it is likely to still be monitoring uncontrolled resources if managing the premises to maximise the customer's self-consumption of PV.

DEFINITION

Flex bidding

Flex bidding refers to a VPP participating in the wholesale market where the quantity of a bi-directional offer is defined at the 'flex' level (controllable devices) rather than at the NMI. See section 5.3.2 for more details.

CASE STUDY

Differences in VPP operational risk across DOE allocation points

The differences in VPP operational risk between the Net NMI DOE and Flex DOE approaches can be illustrated by considering the example of a VPP that is participating in wholesale dispatch with flex bidding while managing a zero-dispatch target and zero export DOEs.

Under Net NMI DOEs, the controlled load and generation must consider the non-controllable loads and generation of each site. To ensure conformance to the dispatch target and the DOE, the aggregator would need to either:

- Withhold capacity, therefore reducing the amount of energy in the market
- Run the risk that if the uncontrolled load were to exceed the amount of DER generation at the premises, and this wasn't accounted for in its bi-directional offer, then it would be non-conforming to its wholesale dispatch target
- Run the risk of non-conformance to the DOE if the uncontrollable load reduces.

Under a Flex DOE approach, key considerations include:

- If a single VPP operator is managing all controllable resources at the site, then it will receive a single Flex DOE for those resources from the DNSP.
- If multiple VPP operators are managing different controllable resources at the premises, depending on the implementation, the DNSP would either need to send separate Flex DOEs to each entity (or direct to each device) or a single Flex DOE to a site 'lead aggregator'.

The customer could nominate a single entity to be responsible for managing all controllable resources at the site. However, in practice, current DER interoperability barriers preclude this from occurring.

It is important to note that DER interoperability barriers also impact Net NMI DOEs as they can inhibit VPPs from coordinating all customer resources at a premises (even if customer consent is granted), potentially leading to breaches in DOEs.

Theoretically, and subject to the DER interoperability challenges being resolved, the VPP would face lower operational risk under a Flex DOE approach when managing conformance to DOEs and wholesale dispatch targets, as there are less variables to manage.

163 AER. 2022. Flexible Export Limits: Issues Paper October 2022, p 45, section 5. https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf.

INSIGHTS

Considerations for DOE conformance

Under both Net NMI and Flex DOE approaches, it is important that mechanisms are put in place to record customer consent on who is responsible for managing DOE conformance on behalf of the customer so that effective conformance and compliance frameworks can be implemented.

It is equally important to remove DER interoperability barriers, so that nominated VPP operators (following customer consent) are capable of managing customers' controllable devices and executing their responsibilities for DOE conformance. This will also remove barriers to customers moving between services providers and improve customer choice.

4.3.7.2 Forecasting of uncontrolled resources

As discussed previously in this section, forecasting of uncontrolled resources (load/generation) is a key input into the calculation of Flex DOEs at a premises. Accordingly, a key consideration for the calculation of a Flex DOE will be which actor is best placed to forecast the uncontrolled resources.

DNSPs currently produce aggregate net system load forecasts across their networks (although not at NMI connection point level) for operational and planning[164] purposes. This is different to the forecasting capabilities required to produce DOEs.

Recognising that basic DOEs can be developed using coarse modelling / forecasting techniques, Project EDGE tested a more sophisticated approach to forecasting that involved NMI-level forecasting across the network. Such an approach may be required as DER penetration increases.

Using historical smart meter data for a chosen network area, this approach produces a forecast for future NMI-level power flows using parameters such as solar vs non-solar connection points, correlation to forecast weather conditions (ambient temperature, solar irradiance, cloud cover, etc), and days of the week.

This forecasting approach is quite new and low-level accuracy was experienced in Project EDGE. However, the approach can improve over time as the methodology is refined through better use of machine learning algorithms.

Forecasting to inform Flex DOE calculations would need an even greater level of detail to identify differences behind-the-meter between controllable and uncontrollable resources. This would be complex and require visibility of behind the meter data, which DNSPs currently do not have. Alternatively, forecasts of uncontrolled loads at each NMI could be provided to DNSPs by third parties (e.g. aggregators) to allow the DNSPs to calculate the spare network hosting capacity for the controlled flexible devices. Recognising that any single aggregator is likely to only have visibility of a minority of network customers, depending on the customer coverage these third-party forecasts provide, they may be used as direct inputs or to inform the DNSP's uncontrolled load forecast.

Depending on the sources of data used by DNSPs, their Flex DOE calculations are likely to be inaccurate and inefficient to begin with, due to a need to apply conservative buffers in the DOEs that account for risk/uncertainty in forecasting accuracy. Machine learning algorithms may also improve these factors over time.

To calculate Flex DOEs, DNSPs would need to invest in new operational forecasting capabilities beyond those currently required or those required to develop NMI-level DOEs. These capabilities would need to be supported with a level of visibility appropriate for the task.

The level at which the forecast is produced would depend on the calculation model. For example, a calculation model forecasting at the NMI level (such as the LV network model tested in Project EDGE) would need forecasts produced at NMI level. However, if a DNSP's most accurate forecasting capabilities were at the sub-station level, it would produce forecasts at the feeder level.

As shown in the GridQube case study (see section 4.3.7.5), there are other approaches and techniques that could be applied to calculate Flex DOEs, which industry could explore further.

164 AER. 2017. Final Decision: Distribution Annual Planning Report Template v.1.0 June 2017. https://www.aer.gov.au/system/files/DAPR%20Template%20V%201%20-%20June%202017.pdf

4.3.7.3 **The ‘unlocking CER benefits through flexible trading’ proposal is DOE agnostic**

AEMO’s ‘unlocking CER benefits through flexible trading’ rule change would enable customers to separate their controllable electrical resources and have them managed independently from their passive load without needing to establish a second connection point to the distribution network. This option would offer greater flexibility and expanded choice around how customers manage and engage with their DER.[165] The rule change proposal is discussed further in section 5.3.2.4.

The rule change proposal notes the application of DOEs could be retained within the scope of connections made directly to the distribution network. Alternatively, DOEs could be designed so that they apply to connections beyond the distribution connection point. This means the rule change proposal is DOE agnostic and could be applied as Net NMI DOEs or Flex DOEs.

Regardless of the allocation point, the rule change proposal notes DOEs need to be designed to accommodate complex connection point arrangements existing in the NEM today (for example, embedded networks or single users with multiple connection points). Accordingly, if those complexities can be accommodated, flexible trading arrangements would also be accommodated.

INSIGHTS

Considerations for the concept of Flex DOEs*

The AER’s Flexible export limits issues paper notes the Distributed Energy Integration Program’s (DEIP) DOE working group’s capacity allocation principles, which were adapted for flexible export limits.

One of the principles is that capacity allocation can initially be based on net exports and measured at the customer’s point of connection to the network (NMI).

The issues paper notes the location of flexible export limit (DOE) applications is a topic that should be considered for future actions and acknowledges there may be additional benefits for future applications with the integration of further interoperability behind the connection point.

Project EDGE supports the AER’s recommendation that this concept be further tested and trialled across multiple companies and networks so that options are clear to industry.

Following the AER’s recommendation, cost benefit analysis of Flex DOEs could be undertaken to inform future DOE design and rollout.

163 AEMC. 2023, Direction Paper: National Electricity Amendment (Unlocking CER Benefits Through Flexible Trading) Rule 2023 – National Energy Retail Amendment (Unlocking CER Benefits through Flexible Trading) Rule 2023, p 48. https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

164 SA Power Networks. N.d., Trial Tariffs 2023-24. https://www.sapowernetworks.com.au/public/download.jsp?id=320663#:~:text=The%20trial%20tariff%20Electrify%20provides,%3A00am%20%E2%80%93%204%3A00pm.

165 AEMC. 2023, Direction Paper: National Electricity Amendment (Unlocking CER Benefits Through Flexible Trading) Rule 2023 – National Energy Retail Amendment (Unlocking CER Benefits through Flexible Trading) Rule 2023, p 48. https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

* Sources: AER (2022) Flexible Export Limits: Issues Paper, https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf;

ARENA, Dynamic Operating Envelopes Workstream, https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/

4.3.7.4 **Potential application of Flex DOEs to flexible loads**

The box below considers EVs as a use case for Flex DOEs. Applying DOEs to the net NMI energy flow combines the essential service load with the spare capacity signal. As uptake of EVs and other flexible loads increases, there could be benefits from applying import DOEs to flexible loads rather than at the connection point.

This is similar to existing approaches that DNSPs take to flexible loads, including controllable load tariffs and new types of co-ordination tariffs, such as SAPN’s Diversify trial tariff.[166] SAPN’s trial tariff offers a daily rebate to residential customers with an EV where they allow SAPN to regulate the charging rate of their smart EV chargers (by sending a targeted DOE to the device) on the rare occasions when the distribution network has limited capacity.

CASE STUDY

Flex DOE use case for EVs

In its flexible export limits issues paper, the AER notes that DOEs offer a more flexible approach to managing DER, and benefits include more efficient use of the existing shared distribution network hosting capacity during times of constraint. DOEs enable customers’ discretionary, flexible DER capacity to be time-shifted to defer network augmentation. This increases network efficiency and reduces network cost to all consumers’ electricity bills.

Applying DOEs to the net NMI energy flow combines the essential service load with the spare capacity signal. As uptake of EVs increases, there could be benefits from separating the two with respect to import DOEs. During peak demand times where there is network congestion, Flex DOEs (applied directly to EV chargers) could constrain EV charging only, rather than essential loads. This could defer the need to build out the network to accommodate unconstrained EV charging, saving costs for consumers and maintaining system security.

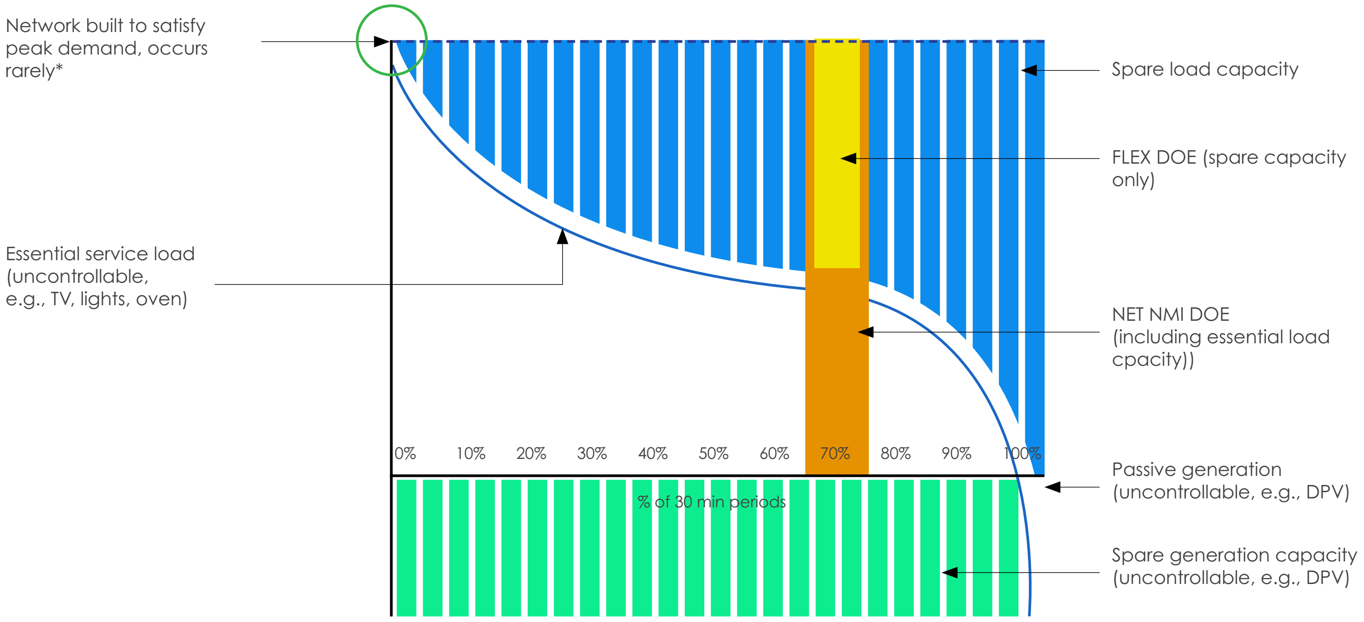
This separation in the DOE could also provide a transparent signal of spare network capacity, informing efficient network augmentation. Networks and the regulator would be able to clearly determine when network capacity to serve customer uncontrolled load (essential service) is reaching its limit, warranting network reinforcement.

Import DOEs were calculated but not tested in practice in Project EDGE because doing so with the Net NMI DOEs used in the field trial would have risked impacting customers’ essential service. However, as industry considers the topic of DOE application point, it should explore both export and import use cases.

The figure below illustrates the concept of a Flex DOE compared with a Net NMI DOE in the context of an indicative network load duration curve.

166 SA Power Networks. N.d., Trial Tariffs 2023-24. https://www.sapowernetworks.com.au/public/download.jsp?id=320663#:~:text=The%20trial%20tariff%20Electrify%20provides,%3A00am%20%E2%80%93%204%3A00pm

Figure 45 | Illustration of the different DOE allocation point approaches



Source: AER. 2022, Flexible Export Limits Issues Paper, Appendix 5.

4.3.7.5 **Theoretical desktop comparison of Net NMI DOEs and Flex DOEs**

As Flex DOEs were not tested in Project EDGE's field trials, a desktop comparison between a NMI DOE and a Flex DOE was undertaken to understand which may provide higher network hosting capacity.

A 'pseudo-flex' DOE was calculated as a simplified version (perfect hindsight Net NMI DOE minus actual uncontrolled power forecast(net)) of what an actual Flex DOE would likely be in practice. This means there are limitations to the assessment, and the results were based on how the aggregators could have performed rather than how they actually performed.

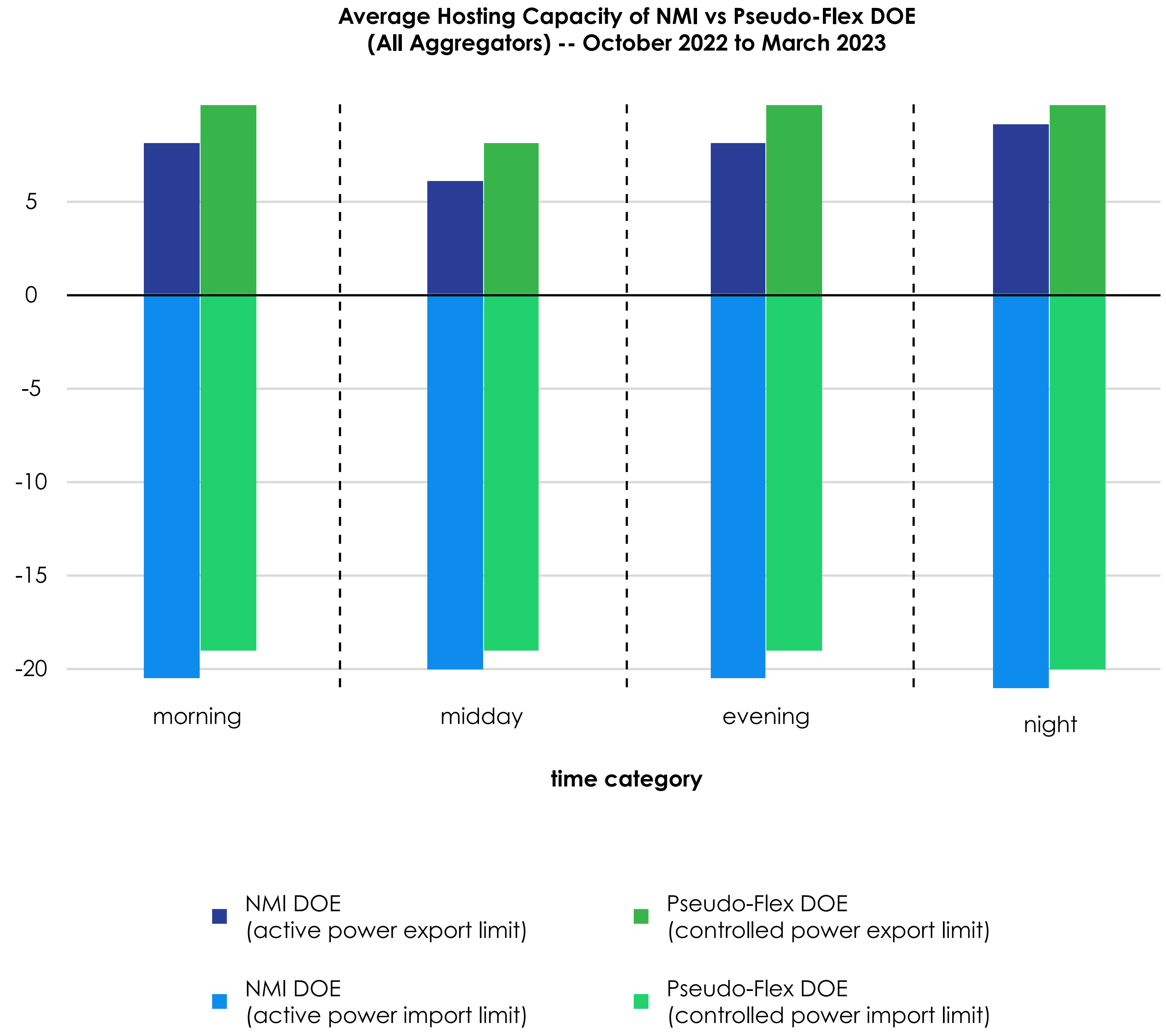
The analysis covered the time period in which all three active aggregators were participating in the field tests (October 2022 to March 2023). The desktop analysis compared both DOE approaches (Net NMI DOE and pseudo-flex DOE) against the same aggregator field test activity (24 hours, 7 days a week across the analysis time period, including any price events that occurred during that time, and across the shoulder and summer seasons, and business-as-usual aggregator bidding and dispatch behaviour (primarily driven by self-consumption)).

The desktop data assessment found, for all times of the day, the pseudo-Flex DOE provided more hosting generation capacity than a NMI DOE.

For clarity, this indicates more hosting generation capacity that could be re-allocated. Both a NMI DOE and Flex DOE would enable the same amount of generation (since the total actual spare distribution network capacity does not change) assuming demand forecasts are accurate. This is illustrated in 46 for a sample site.

* For example, in QLD, 16% of assets are utilised 1% of the time and load peaks are increasing. See: https://www.aemc.gov.au/sites/default/files/content/963b836e-2970-4623-8ea5-e4bc5d659d9c/Energex-presentation.pdf

Figure 46 | Desktop assessment results comparing NMI DOE and Flex DOE hosting capacity that could be utilised



The bars above the black line show the average hosting capacity (average DOE export limit) for generation for NMI DOEs (dark blue) compared with pseudo-Flex DOEs (dark green). The bars below the black line show the average hosting capacity (average DOE import limit) for load for NMI DOEs (light blue) compared with pseudo-Flex DOEs (light green).

Above the black line, the dark green bars (pseudo-Flex DOEs) are higher than the dark blue bars (NMI DOEs) at all times of the day. The desktop data therefore indicates the pseudo-Flex DOEs could utilise the diversity of other loads, whereas the Net NMI DOE only applies to the load at one site.

For the pseudo-Flex DOEs, the generation is a bit higher, and the load limit is a bit lower because the uncontrolled load has been accounted for in that constraint. The limit does not change; it is just how it is expressed.

Flex DOEs have also been tested in other ARENA field trials by GridQube, an Australian software company providing technology services to help DNSPs manage their networks. The case study below summarises GridQube's approach to trialling and comparing Flex DOEs with Net NMI DOEs.

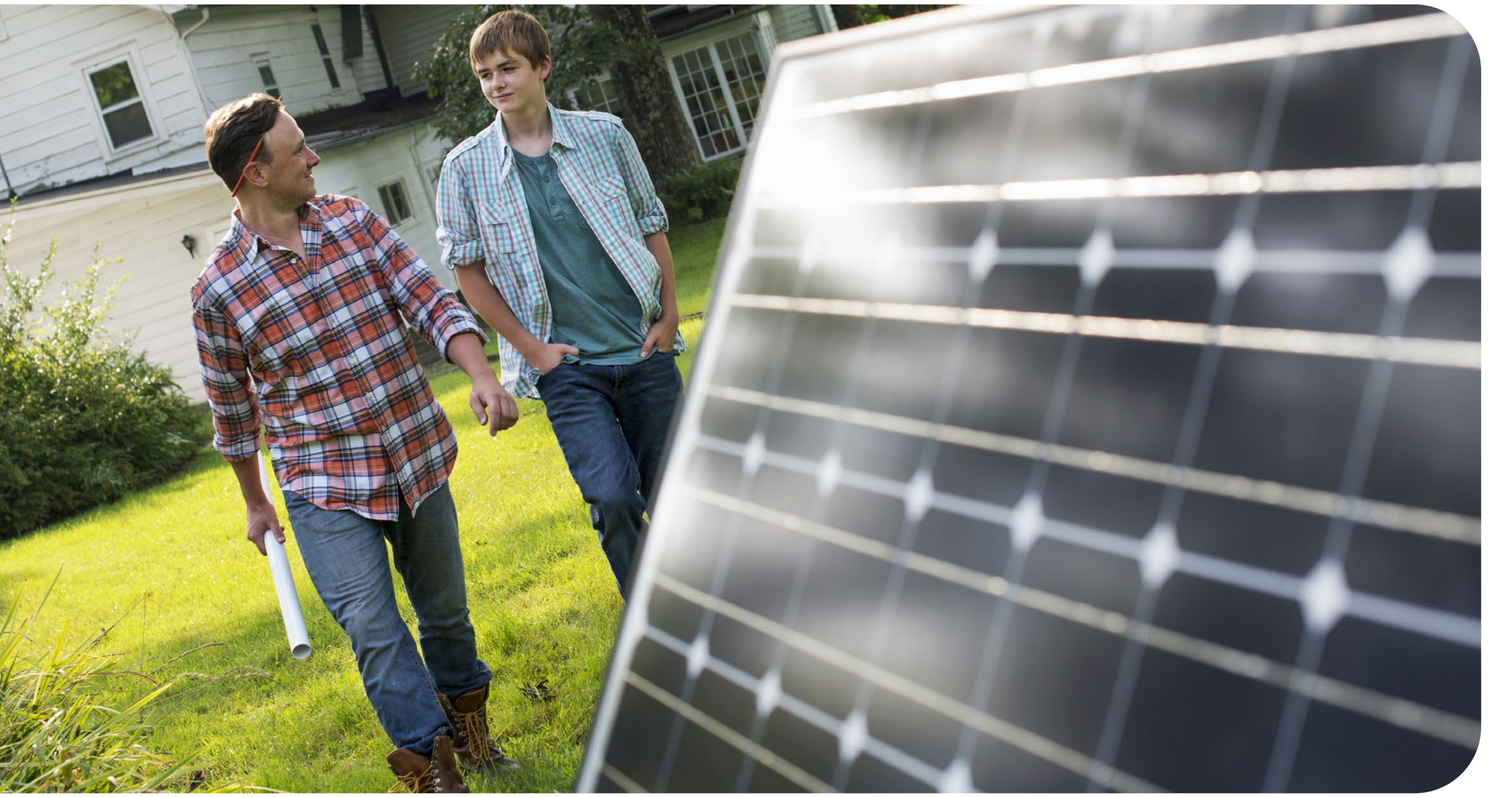
The trial showed that on a peak generation (sunny) there was a 20% improvement in the amount of rooftop PV generation released into the network using a Flex DOE.

With a Flex DOE, if the uncontrolled load increased at one site, the aggregator could still generate the same amount of rooftop PV to satisfy the uncontrolled load. Under a Net NMI DOE, if that uncontrolled load changed, the controlled generation and load at the site must also change to achieve a net position at the site.

By contrast, as Flex DOEs apply limits to only the controllable assets at the site, any change in uncontrolled load is factored into the calculation of all Flex DOEs as it is highlighting the spare capacity these controlled assets have.

Hence a load change in one site does not need to affect how much rooftop PV generation can occur because that limit is calculated based on an upstream constraint, allowing the generation to be shared across sites that are underneath the constraint.

Additional research is recommended to field test the different outcomes from the DOE point of allocation.



CASE STUDY

GridQube*

GridQube is a software company that develops network management technologies for DNSPs. Trials are ongoing using GridQube's DOE system in an operational, real-time deployment with Ergon Energy and Energex distribution networks in Queensland since 2021.

Using these trials, separately recorded disaggregated load and generation data for both a peak generation (sunny) and low generation (cloudy and rainy) day were applied to one of the network's feeders to assess the likely performance of alternative DOE allocation strategies for different assumed levels of PV penetration.

Load and generation data was scaled to match the customer distribution of the selected feeder. The network's standard technical limits were applied to ensure the DOE calculation was realistic and the network's standard DOE calculation parameters were used. Two alternative DOE allocation arrangements were analysed in this study for simulated 50% and 100% PV penetration:

- NMI DOE: allocation to individual connection points – including uncontrolled load
- Flex DOE: allocation to flexible load and generation only – excluding uncontrolled load.

The results for a sunny day were a 20% difference in the amount of rooftop PV generation released into the network using a Flex DOE.

The method and techniques used to provide network visibility and facilitate the calculation of DOEs was a Capacity Constrained Optimisation (CCO) engine on top of GridQube's Distribution System State Estimation (DSSE) engine. In conjunction with DSSE, the CCO provides the capability to calculate DOEs, in near real-time, as an additional allocation on top of uncontrolled essential load (Flex DOE) or as a total allocation to the entire site (NMI DOE).

Combined with the ability to run real-time, this enables the option to exclude uncontrolled essential load from the DOE calculation and calculate DOEs to allocate only the spare capacity that is not utilised to service uncontrolled and essential loads and generation. GridQube's research in Queensland found additional export could be accommodated using the state estimation method for previously constrained DER.

The state estimation technique applied by GridQube provides economically achievable distribution network visibility that generates a complete and consistent view of the electrical state of the network with limited input data. Accordingly, this approach would be particularly valuable when applied downstream of zone substations with limited monitoring and increased DER connections.

The state estimation approach does not require 100% smart meter penetration in the distribution network. The approach was also validated in the ARENA†-funded Solar Enablement Initiative (2017-2019). That initiative also demonstrated the technical feasibility of achieving full network visibility from incomplete measurement data, and that most Australian DNSPs would likely have enough existing data to apply state estimation. The initiative involved participation from multiple networks representing different data monitoring capabilities, ranging from high smart meter penetration (United Energy, 2 feeders trialled) and lower smart meter penetration (Energex, 3 feeders and TasNetworks, 2 feeders).

Research on GridQube's approach demonstrates:

- The feasibility of different approaches to DOE calculation that can utilise different data and measurements in distribution networks
- A state estimation-based approach, similar to the transmission system, that can be applied across a range of networks and does not require 100% smart meter penetration
- Most DNSPs are likely in a position to implement state estimation based on currently available data, with future data improvements allowing for less conservative DOE calculations
- The feasibility of calculating Flex DOEs.
- Flex DOE limits, calculated on an upstream constraint can release more PV export.

* Sources: AER. 2022, Flexible Export Limits Issues Paper, p 63. https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf

† Source: ARENA. 2019, Solar Enablement Initiative Final Report. https://arena.gov.au/assets/2018/02/uq-solar-enablement-initiative-final-report.pdf

INSIGHTS

The point of DOE allocation requires further exploration

The point of DOE allocation – whether it is at the NMI or at the flexible devices only – is a topic that requires further exploration. It is critical industry agrees on a way forward and makes informed decisions based on the approach that would provide longer term efficiency benefits to the system and all electricity consumers.

It will also be critical that any decisions and solutions are flexible to work with new market arrangements and can be adapted to support new and innovative business models as DER's integration into the power system and markets matures and evolves.

4.3.8 DOE roadmap considerations for industry

The CBA found that DOE design improvements (using a more accurate calculation methodology and more frequent calculation of DOEs) provide benefits through avoided costs under higher DER penetration and participation rates.

The benefits of more sophisticated DOEs are also supported by UoM's work, discussed in section 4.3.3, comparing the technical efficacy of progressively more sophisticated DOE design for a range of DER penetration and participation levels.

The AER's preliminary position, in its consideration of policy direction and advice in relation to the implementation of DOEs in the NEM, is that prescriptive approaches to the DOE calculation methodology are not needed at this stage.[167]

This approach allows DNSPs to be innovative in their approaches. Additionally, DNSPs differ in their approach to managing their networks and are best placed to use their understanding of their respective networks to develop the DOE design that best suits their network topography and DER penetration levels.

For example, Victorian DNSPs have high penetration of smart meters that provide increased LV network visibility and access to network data. Meanwhile, Queensland DNSPs do not have high penetration of smart meters but have developed flexible approaches to manage the network during periods of high demand (e.g. the use of controlled loads), and are trialling alternative approaches and techniques to obtain reliable and consistent visibility of their networks with limited data (see GridQube case study in section 4.3.7.5.

Additionally, some networks are predominantly rural (e.g. Ergon Energy in Queensland) while others are predominantly urban (e.g. Citipower in Victoria). UoM's findings highlighted the efficacy of different DOE approaches is influenced by various factors, including the amount of DER in the network and the physical network type (see section 4.3.1).

The AER's approach not to establish prescriptive DOE calculation methodologies also aligns with UoM's recommendation that each network would need to conduct a CBA for its own network to inform its decision on when to move from simple to more sophisticated approaches.[168]

Another consideration for a DOE rollout is the application of DOEs to FCAS. This was not tested in Project EDGE but was raised in the VPP Demonstrations[169] as a future development to consider. The VPP Demonstrations' final knowledge sharing report recommended the exploration of tiered DOEs over time. The tiers could represent one DOE for system normal operation and one for contingency events that would allow the system normal DOE to be exceeded temporarily when delivering contingency FCAS.

167 AER. 2022, Flexible Export Limits: Issues Paper October 2022; p 63. . https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf,

168 Project EDGE. 2023, Project EDGE: Testing different DOE approaches at DRE penetration levels in real-world networks. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge--testing-different-doe-approaches-at-der-penetration-levels-in-realworld-networks--work.pdf?la=en

169 The VPP Demonstrations were a collaboration between AEMO, ARENA, AEMC, AER and members of the Distributed Energy Integration Program (DEIP). AEMO. N.d., Virtual Power Plant (VPP) Demonstrations. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations

170 AEMO. 2021, AEMO NEM Virtual Power Plant Demonstrations: September 2021 Knowledge Sharing Report #4, p 6. https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf?la=en

INSIGHTS

Considerations for DOE implementation approaches

The CBA suggests an accelerated DOE rollout emphasising maximum coverage of DER customer sites can deliver consumer benefits sooner, particularly if DER uptake continues at the forecast rate.

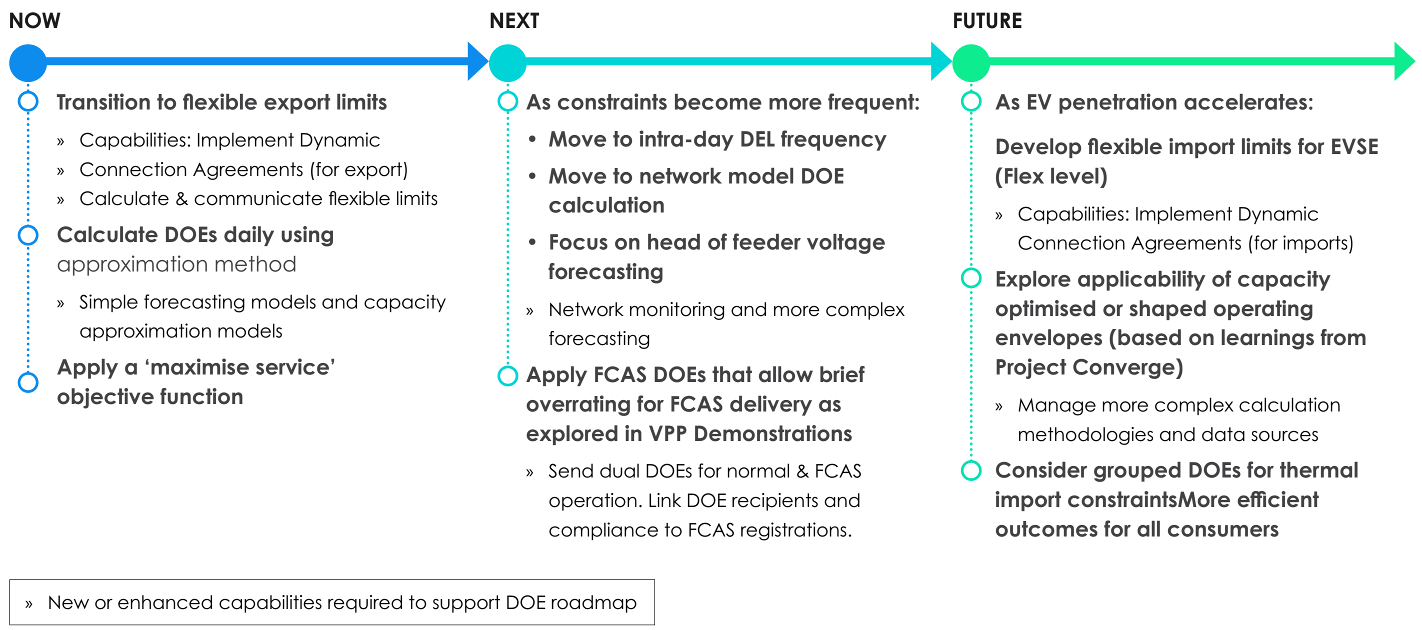
As DOEs are a relatively new concept and would represent a significant shift in the way customers are able to use their DER, simple implementations before adding sophistication over time would facilitate such a rollout.

This approach could also enable the value of DOEs to be realised quickly, and allow DNSPs to invest incrementally in network monitoring and more sophisticated model-based DOEs over time, guided by localised DER penetration levels. DNSP investment in developing capabilities should include a focus on improvements to forecasting the head of feeder voltages to maximise the utility of DOEs.

A progressive approach would also facilitate trials of different approaches; for example, Flex DOEs.

47 outlines a potential accelerated DOE development roadmap that should deliver net economic benefits aligned to the findings from the CBA, UoM analysis and Project EDGE field trials. The purpose of sharing this potential development roadmap is to help industry and policy makers form their own roadmaps aligned to network and business needs, and policy objectives.

Figure 47 | Accelerated DOE development roadmap



4.4 Key insights and implications for industry

The CBA identified that DOE design improvements would provide economic benefits for all consumers. The UoM techno-economic modelling also identified the benefits of more sophisticated DOE design for a range of DER penetration and participation levels. Field trial data and desktop assessments conducted for Project EDGE have also clarified the implications of different approaches and pre-requisites for improving the design of DOEs.

Project EDGE notes the following key insights and implications for industry.

For policy makers

- Identify and implement a national approach to implementing DOEs that standardises key elements such as the DOE objective function and communication protocols. This could include setting out a roadmap of DOE design developments that improve the efficiency of DOEs, with recommended trigger points as DER penetration increases.
- Recognise that DOE design should start simply and progress to more sophisticated design over time as DER penetration increases.
- Recognise that DOEs with the objective function of increasing system technical and economic efficiency are likely to provide the most benefits to all electricity consumers in the NEM and could be considered to maximise fairness from a whole-of-system perspective. This aligns to the principles of efficiency for the long-term interests of all consumers in the NEO.
- Support DNSP investment in DSO capabilities to rollout DOEs at scale. This could include reviewing and considering regulatory arrangements to support DNSP investment to develop DSO capabilities and increase spare network capacity to accommodate DER.
- Support customers in their choices. Similar to the findings of the DEIP DOE working group[171] DOEs do not need to be mandated but the customer benefits afforded by choosing a dynamic connection agreement should incentivise widespread uptake when compared to static connection agreements.
- With substantiation, consider DNSP investment in more accurate DOE calculation capabilities as aligning with the NEO's objectives to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interest of electricity consumers.
- To align with the regulatory economic framework for DNSP expenditure, consider whether investment in DOE calculation capabilities could be overseen and tested by the AER to ensure it is prudent and efficient, in line with a network's DER penetration levels and network topologies.
- Consider the use of a DER data hub as a requirement for industry in the future, with the communication of DOEs being the initial primary use case, and collaborate with industry on the design and objectives.
- Support further trials and research to test and identify the potential benefits of the different approaches to the DOE allocation point, recognising that a key decision industry will need to make is the location of the flexible export limit application (the capacity allocation point).
- Support and give priority to the AER continuing with its approach to exploring the DOE allocation point as a future action for industry. Considering the forecast uptake of EVs and electrification of the economy, this topic should be considered in the near future to ensure the sector prepares adequately and lays the necessary foundations while network constraints remain manageable, and to provide industry with clarity when developing their capability roadmaps.
- Consider whether regulatory change is needed to recognise DNSPs' responsibilities to manage distribution network constraints using DOEs.
- Define and implement a framework to manage DOE conformance and compliance.

For DNSPs

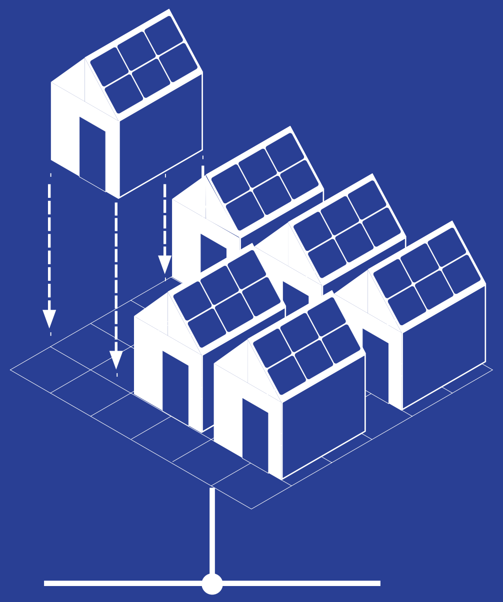
- Engage proactively in efforts to develop a consistent, standardised NEM DOE approach, recognising that a simple, national approach is in consumers' long-term interests.
- Develop their own roadmaps for DOE design developments, giving consideration to starting with simpler and cheaper DOE design to realise value quickly.
- Invest in developing DSO capabilities to support DOE rollout and interactions with DER aggregators around standardised local network support services, and consider producing DSO action plans to articulate how these capabilities will be developed.
- Consider investing incrementally in network monitoring and more sophisticated model-based DOE capabilities over time and guided by network topologies and DER penetration levels.

171 DIEP. 2022. DEIP Dynamic Operating Envelopes Workstream: Outcomes Report. https://arena.gov.au/knowledge-bank/deip-dynamic-operating-envelopes-workstream-outcomes-report/

- DOE information will need to be shared with customers and third parties transparently. Customers, and aggregators they nominate will need information on DOEs relevant to their location to make informed choices, and also information on their performance. Further work is required to define what other information customers / aggregators want or need.
- Work with AEMO to establish a coordinated VPP enrolment / registration process.

Table 8: Areas for further research on DOEs

Areas for further research
Flex DOEs
As discussed in section 4.3.7, there are two approaches to DOE allocation. The simpler approach calculates DOEs for a site based on the electrical limits that apply at the connection point to the distribution grid. This is the approach trialled in Project EDGE. This calculation accounts for all load and generation at the site, regardless of whether it is controllable or not. To conform to these DOEs, an aggregator would need to continuously manage the controllable devices to compensate for changes in uncontrolled load and generation at the site. The other approach, referred to in this report as Flex DOEs, only sets limits for the outputs of controllable DER devices. This potentially allows aggregators to conform with Flex DOE limits without needing to compensate for changes in uncontrollable generation or load. However, this does not eliminate the need to ensure that power flows at the connection point remains within system limits. Project EDGE used case studies of ARENA projects and trial data to evaluate how an aggregator could theoretically have performed under Flex DOE arrangements. However, Flex DOEs were not included in the EDGE field trial and further research would support a definitive assessment of the feasibility and value of such arrangements.
Capacity optimised DOEs
Section 4.3.6.2 discusses capacity optimisation as an approach to improve network hosting allocation. This approach is based on the DNSP receiving a DER available capacity forecast from the aggregator rather than using the DER device rating. If the aggregator forecasts its full DER rating capacity is not available, the DNSP could then re-allocate capacity to other NMIs with available DER capacity. This potentially avoids allocation of capacity to sites that are not expected to utilise their full allocation and allows the DNSP to reallocate any such spare capacity to other constrained sites on the same network segment. This was not trialled in Project EDGE but an ex-post analysis of capacity optimised DOEs was undertaken. Results from this analysis across a limited number of DER sites showed that capacity optimisation could provide significant benefits to constrained sites. Further research and testing of this concept, through field trials and with more sites and data, is needed to understand if there is merit in implementing this approach for DNSPs, and what the potential implications or unforeseen consequences could be.
Economically optimised DOEs
Section 4.3.6 discusses desktop study results that indicate there is value to be unlocked in economically optimising the network capacity allocation to customers via DOEs. Further research should explore how the reallocation would work, and seek to define the critical mass and pre-conditions needed to graduate beyond capacity optimisation (which could work with only one aggregator) to economic optimisation with many aggregators. Both DOE calculation as well as market mechanisms (for example a secondary market) should be investigated.



WHOLESALE MARKET INTEGRATION

This chapter focuses on the research question:

How can integrating DER into the NEM facilitate efficient activation of DER to respond to wholesale price signals, operate within network limits and progress to participation in wholesale dispatch over time?

Overview

- The aggregate capacity DER is expected to provide by 2050 could contribute to a more affordable and reliable power system for all consumers – provided DER is integrated into the power system and wholesale electricity markets. Action must be taken now to design and implement enduring solutions to integrate and coordinate DER in a high DER future.

- If DER is not coordinated, there are likely to be gaps in the power system's reliability and additional investment may be needed on other large-scale resources that can be coordinated to maintain reliability. This would increase overall costs for consumers.

- Visibility of DER is a critical enabler to integrating DER and maintaining a secure and reliable power system. Project EDGE identified and explored key visibility considerations in a high DER future:
  - How the integration of DER can facilitate understanding and maintaining essential power system requirements, such as predictability and dispatchability
  - Addressing AEMO's current visibility challenges, which include insufficient ability to accurately forecast operational demand given variability in rooftop solar output, inability to unbundle flexible resources from passive resources and no access to performance data for price-responsive DER
  - Facilitating progressive wholesale participation as a key enabler for DER visibility
  - Having visibility of DOEs that can coordinate DER output for sites not participating in a VPP
  - Having visibility of coordinated DER commitments made off-market
  - Adopting a DER data hub approach as a scalable and long-term enabler of visibility (see Chapter 6).

- Project EDGE tested progressive levels of participation of coordinated DER in the wholesale market. Three active aggregators participated in an off-market field trial that ran 24/7 for 333 days, using real forecast and actual market prices for Victoria. The field trial identified three over-arching factors as being critical to the efficient and effective integration of DER into the wholesale market:

  Factor 1: Moving beyond the self-consumption only model, this will take time. DER consumers' priorities for self-consumption do not always align with system needs, and self-consumption only models mostly ignore revenue opportunities from price signals. It will take time for consumers to trust that VPPs can use their DER to deliver services back to the power system, and still maintain high levels of personal utility.

  A natural progression that adds value but maintains self-consumption as a key objective would introduce price-responsiveness at price points the aggregator has calculated to provide sufficient value to the customer (i.e. either very high or negative wholesale prices that exceed certain thresholds).

  Factor 2: Aggregator capability development can be rapid but needs appropriate incentives. Based on experience developing capability for the field trial, it will take aggregators time to improve their performance to the level of sophistication required to become dispatchable resources that do not compromise power system security. The field trial identified the main capabilities that aggregators need to develop for wholesale market participation:
  - Reliable forecasting capabilities to provide longer-range forecasts of available capacity
  - Developing bidding and re-bidding behaviour suitable for market participation
  - Providing accurate and complete operational data, noting that these capabilities could be costly and take time to develop
  - Coordinating DER as a portfolio to conform with dispatch targets, including linearly ramping from one dispatch target to another
  - Conformance of DOEs sent from DNSPs to preserve local network and broader NEM power system security.
  - Best practice communications and cyber security capabilities to maintain system security, including compensatory controls
  - An understanding of market risk dynamics and performance requirements for scheduled resources
  - Ability to manage scheduling conflict, deliver wholesale and local services simultaneously and optimise services in cooperation with AEMO and DNSPs.

Factor 3: Applicability of scheduled resource operating requirements to DER. The obligations on scheduled resources in the NEM and the sophisticated capabilities required to meet expected performance standards are wide-ranging. Some of these obligations should be applied equally to DER, but there may be a case for DER to meet alternative performance standards for some obligations – notably data communications standards.

- Project EDGE field trial results show it is possible for aggregators to deliver wholesale services. A stepping-stone approach would give aggregators time to progressively develop the capabilities needed for participating in the wholesale electricity market as scheduled resources. As VPPs scale, this approach can strike a balance between the costs of market participation and visibility/dispatchability benefits to support power system security. It would also facilitate aggregators unlocking revenue streams (and therefore enabling business models other than self-consumption-only).

- Policy makers should consider progressing reforms that would facilitate a stepping-stone approach to DER integration that includes at least three stepping-stones:
  1. Providing visibility through forecasts
  2. Passive market participation through "self-dispatch" bids and offers that don't influence the clearing price calculations but allow aggregators that have demonstrated sufficient capabilities to participate as price takers and self-nominate dispatch targets
  3. Graduation to fully scheduled and dispatchable resources.

- Insights from the Project EDGE field trial regarding a stepping-stone approach can continue to inform the development of the proposed approach for integrating price-responsive resources into the NEM.[172]

172 AEMC. N.d., Integrating price-responsive resources into the NEM. https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

5.1 Context

5.1.1 The need for DER market integration and coordination

A predictable and operable power system in a high DER future will require DER to participate in wholesale electricity markets.

Scale of DER anticipated

AEMO's 2022 ISP anticipates a 'decentralisation, digitalisation and democratisation' of the NEM by 2050 under the 'step change' scenario[173], identified by stakeholders engaged in the development of the ISP as the most likely scenario. Figure 48 illustrates the forecast scale of this change until 2050:

Over 100GW of DER are connected to the NEM, including an increase from approximately 15GW[174] of aggregate residential rooftop photovoltaic (PV) capacity to 69GW, representing 40% of total NEM installed capacity (left side of Figure 48).

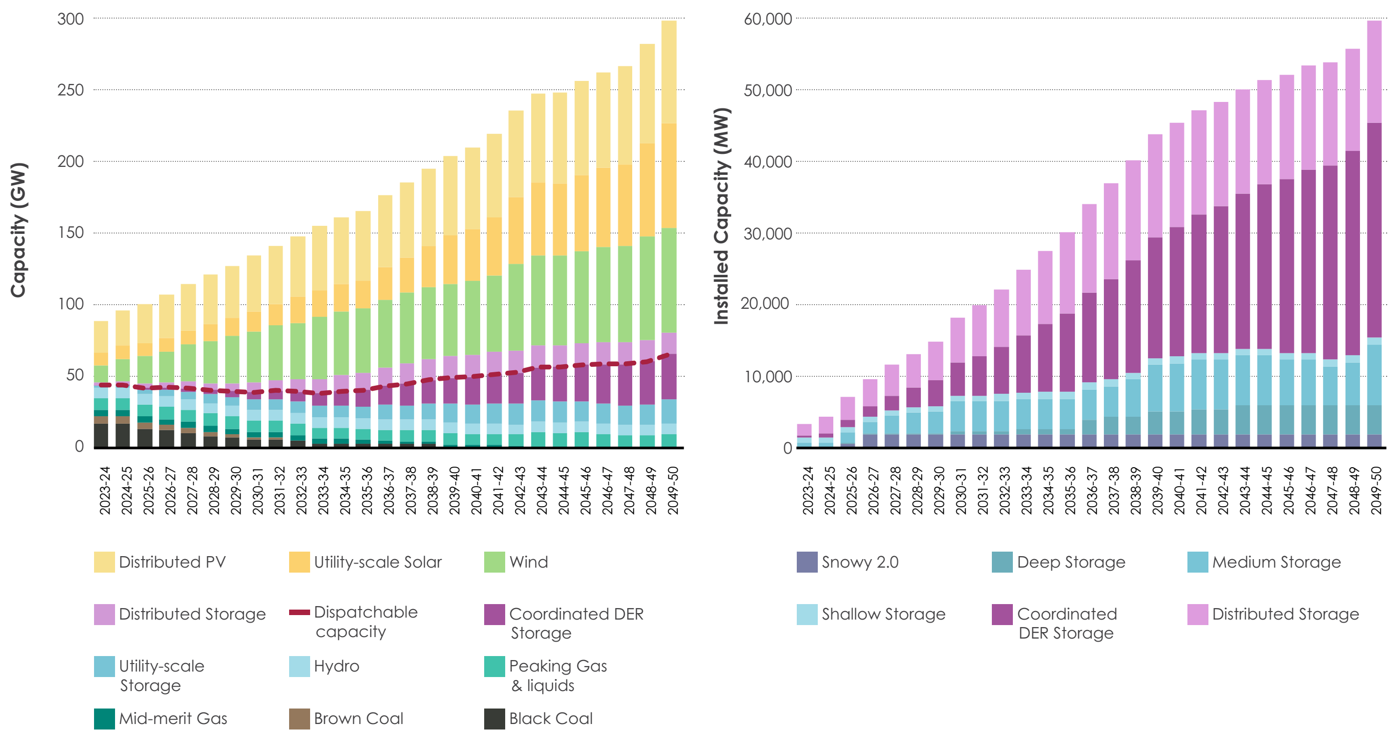
- Over 75% of storage capacity could be connected to the distribution network (right side of Figure 48)
- Coordinated DER storage (31GW, including 7GW of V2G EVs) may represent almost half of total dispatchable capacity.

DEFINITION

Coordinated DER storage

Coordinated DER storage refers to the DER that is integrated and responsive to power system and market needs, that is, it is visible, predictable and operable.

Figure 48 | 2022 Integrated System Plan most likely scenario: generation mix (left), storage mix (right)



Source: AEMO, 2022 Integrated System Plan[175]

173 AEMO. 2022, 2022 Integrated System Plan, p 9; p 54. https://aemo.com.au/initiatives/major-programs/nem2025-program/about-nem2025-program https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

174 AEMO. N.d., DER Register Data. https://aemo.com.au/energy-systems/electricity/der-register/data-der/data-dashboard

175 AEMO. 2022, 2022 Integrated System Plan, p 9; p 54. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

At this rate, DER will have a material impact on NEM dynamics and system security in two key ways:

- A five-fold increase in rooftop PV will cause very low operational demand[176] periods on sunny, mild days with high PV generation and low consumer demand.
- Without being coordinated – that is, without being integrated into market systems – this amount of DER storage operating dynamically may cause material swings in the supply-demand balance that are difficult to forecast.

AEMO's ability to keep supply and demand balanced at all times is critical to maintaining power system security and 'keeping the lights on'. This process is managed through 'scheduling' resources to meet demand for electricity. When DER are coordinated, forecasts are provided to AEMO by market participants representing the DER, meaning that it is no longer a challenging exercise to forecast and schedule these resources.

There is a risk of not achieving a high level of coordinated DER. If this occurs, additional investments may be required in other network and large-scale utility assets that can be coordinated.

Coordinating DER will improve the reliability of the NEM

AEMO's 2023 ESOO identifies numerous reliability gaps over the 10-year horizon modelled[177].

Figure 49 shows the results of a DER coordination and demand side participation growth sensitivity modelled, relative to the 2023 ESOO central (step change) scenario. If coordinated DER and demand reduction occurs to the scale projected, the reliability forecast is expected to improve considerably. The figure compares the results of the sensitivity scenario and the central (step change) scenario. The dark lines represent the DER coordination and demand side participation growth sensitivity scenario, while the dashed lines of the equivalent colour reflect the central (step change) scenario.

The modelling shows that in NSW (blue lines), the forecast expected unserved energy[178] under the sensitivity scenario (solid blue line) is above the reliability standard from 2025-26, consistent with the central (step change) scenario (dashed blue line). However, the reliability risks are projected to be lower over the longer-term horizon.

In Victoria (purple lines), the expected unserved energy under the sensitivity scenario (solid purple line) is within the reliability standard in 2026-27 and 2027-28. However, it is above the reliability standard from 2028-29, consistent with the central (step change) scenario (dashed purple line).

Meanwhile, in South Australia (orange lines), the forecast expected unserved energy under the sensitivity scenario (solid orange line) would be within the reliability standard until 2030-31, when reliability risks increase.

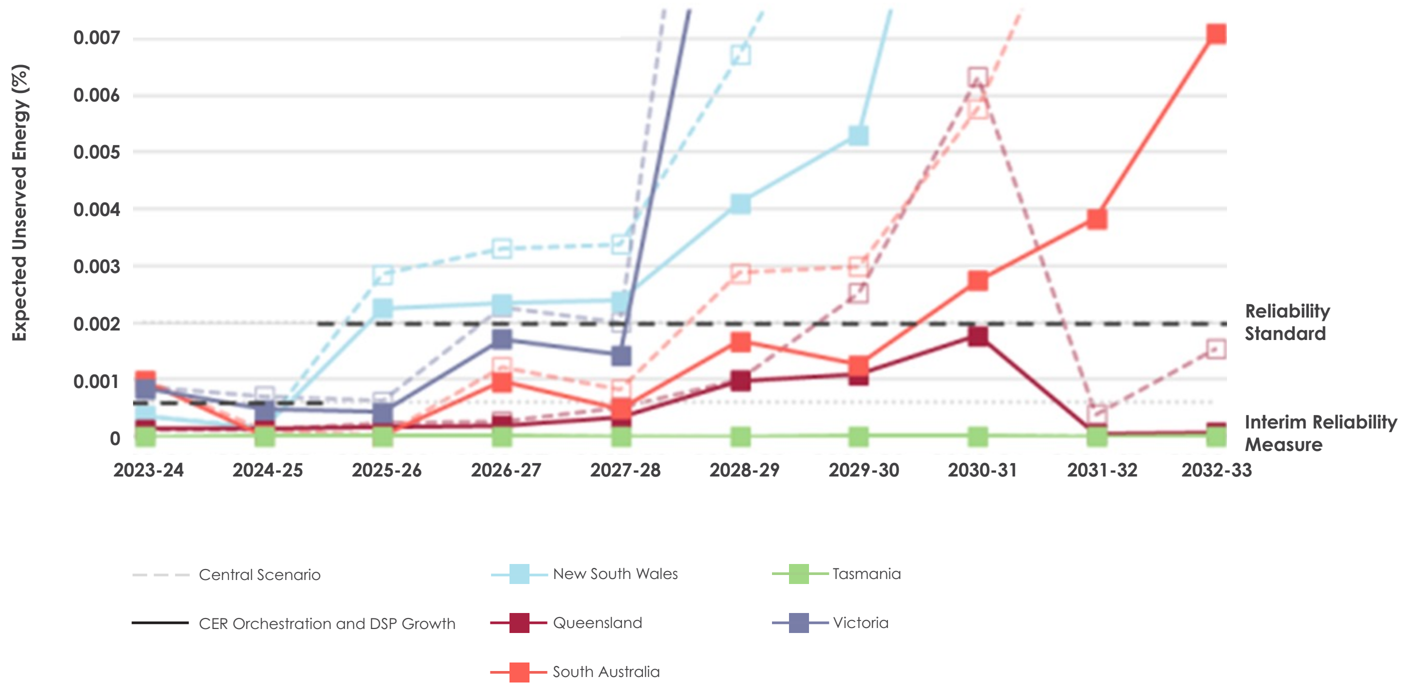
This signals that policy and consumer support for coordinated DER and other demand side solutions are important to achieve the forecast scale and effectiveness needed to lower the reliability risk and reduce the need for more costly large-scale utility solutions.

176 Operational demand is the demand for energy from the NEM. AEMO. 2021. Demand Terms in EMMS Data Model October 2021, p 8, section 1.2. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

177 AEMO. 2023. 2023 Electricity Statement of Opportunities, p 95. https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en

178 Expected unserved energy is the energy that cannot be supplied to consumers. This results in involuntary load shedding due to insufficient levels of generation capacity, demand response or network capability to meet demand.

Figure 49 | The 2023 ESOO's modelled reliability impact (as a percentage of expected unserved energy) of demand side solution delays, 2023-24 to 2032-33



Source: AEMO, 2023 Electricity Statement of Opportunities[179]

The aggregate capacity DER is expected to provide by 2050 could be beneficial to improving the reliability outlook if DER is integrated into the system and markets.

The 2023 ESOO central (step change) scenario includes a strong influence from electrifying business and residential sectors, and a continued consumer uptake of DER. While this scenario includes the forecast rapid uptake of DER. However, it does not assume, for reliability forecasting purposes, that sufficient coordination of DER is successfully enabled to meet power system needs. . A 'DER coordination and demand side participation growth' sensitivity identified that if the material capacity and capability of DER is not utilised to deliver wholesale, system and network support services, then otherwise avoidable investments in large-scale resources will be needed that increase overall costs for consumers.

The sensitivity analysis sought to understand the potential reliability improvement of DER coordination at scale, and demand side participation growth compared to the 2023 ESOO central (step change) scenario assumptions. Over 6GW of coordinated DER uptake, but which is not included in the 2023 ESOO central (step change) scenario, is projected as possible by 2033 across the NEM. However, the ESOO notes these uptake projects are dependent on consumer trends that could influence the degree of DER uptake and coordination uncertainty. For example, consumer purchase decisions and usage requirements, market opportunities, and the value that retailers and aggregators can find for future revenue.

179 AEMO. 2023. 2023 Electricity Statement of Opportunities, p 95. https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en

Opportunity for DER coordination to improve system reliability and affordability

The forecast of coordinated DER storage representing almost half of all dispatchable capacity by 2050 shows the scale of opportunity for DER coordination to support a more affordable and reliable power system for all consumers.

Action must be taken now to design and implement enduring solutions to integrate and coordinate DER in a high DER future.

Insufficient action will likely result in higher costs of electricity supply for consumers, just as they are electrifying their lives (e.g. by transitioning to EVs or replacing gas-fuelled appliances with electric alternatives) and becoming more dependent on affordable and reliable electricity[180]. Some of this cost could come in the form of more frequent customer curtailment – both solar and load (discussed below).

5.1.2 DER visibility

Visibility of DER is a critical enabler to integrating DER and maintaining a secure and reliable power system. Key considerations related to DER visibility in a high DER future include:

- Understanding the essential power system requirements that must be maintained (section 5.1.2.1)
- AEMO's current visibility challenges with respect to DER, including standing data (section 5.1.2.2)
- Progressive wholesale participation as a key enabler for DER visibility (section 5.1.2.3)
- Visibility of DOEs that can coordinate DER output for sites not participating in a VPP (section 5.1.2.4)
- Visibility of coordinated DER commitments made off-market for aggregators that provide forecasts to AEMO, as well as aggregators that do not provide forecasts to AEMO (section 5.1.2.5)
- A DER data hub as the enabler of visibility (section 5.1.2.6).

5.1.2.1 Power system requirements

The operational pre-requisites for managing a secure and reliable power system, which must be maintained throughout the energy transition, are outlined in AEMO's Power System Requirements paper[181] and include:

- **Predictability** – the ability to:
  - **Measure** or derive accurate data on energy demand, power system flows and generation output across numerous timeframes
  - **Forecast** upcoming power system conditions and have confidence in how the system will perform. The ability to forecast is highly influenced by the **visibility** of resources in terms of how accessible information on plant characteristics, output and conditions is to the system operator (see section 5.1.2.2 for more detailed discussion)
- **Dispatchability –** the ability to manage dispatch of scheduled[182]/ semi-scheduled[183] resources and configure power system services to maintain system security and reliability
  - Part of managing dispatch involves ensuring that power flows remain within network limits and that supply and demand are kept in balance in real time.
  - A pre-requisite for dispatchability is that material, price-responsive resources are operable, i.e. they can be receive and respond to operational control (dispatch) signals.

181 AEMO. 2020, Power System Requirements July 202 Reference Paper. https://aemo.com.au/en/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper

182 Scheduled generation refers a to generator that can be registered with AEMO as 'Scheduled' and as such must be considered in the NEM central dispatch process. In the NEM, 'Scheduled' refers to a generating system with an aggregated nameplate capacity over 30MW and attracts a host of corresponding performance standards. AEMO has the ability to control scheduled resources if required for system security and it receives real-time data from the generators.

183 Semi-scheduled generation refers to generating systems with intermittent output (such as wind and solar farms) and an aggregate nameplate capacity of 30MW, or more. AEMO can constrain down semi-scheduled generation if required for system security and it receives some real-time data on performance. Taken from AEMO's Visibility of the power system factsheet.

AEMO. N.d., Visibility of the power system factsheet. https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/0DE87F5ADD5D42F7B225D7D0799568A8.ashx

5.1.2.2 AEMO's current DER visibility

AEMO has confirmed it faces the following current challenges associated with DER visibility[184]

- Insufficient ability to accurately forecast operational demand given variability in rooftop solar output (and associated consumer response)[185]
- No access to measurement data for price-responsive DER, either near real-time telemetry or forecast measurements
- The requirement to take a more conservative approach to constraint management (given the level of uncertainty)
- Inability to unbundle flexible resources from passive resources, either related to solar through the Australian Solar Energy Forecasting System (ASEFS2) or other DER such as hot water.

Another challenge both for AEMO and industry is reliable and complete standing data on location, capacity, and the technical characteristics of DER, in particular the inverters interfaced with the network.[186] Industry identified coverage and completeness of standing data as a paint-point in engagement through Project EDGE.[187]

As DER increases, accurate information about them increases because AEMO's processes will rely heavily on understanding their behaviour.

- Accurate location data is necessary because each DER installation has unique properties that AEMO needs to consider when data is aggregated to the transmission connection point. It also enables identification of DER participating in providing services (which changes how the DER will behave and therefore needs to be forecast.
- Capacity of DER information is important to forecast generation and load shifting.
- Technical characteristics data is particularly important for inverters interfacing the network as these characteristics will determine responses to system disturbances.

These challenges highlight that in order to maintain power system requirements throughout the energy transition, AEMO needs to have visibility of flexible, price-responsive DER.

5.1.2.3 Progressive wholesale participation as a key enabler for DER visibility

The NEM dispatch process is a critical mechanism for AEMO to maintain the essential power system requirements. As DER penetrations continue to grow towards 100GW in the NEM, coordination of DER through progressive levels of wholesale participation will be essential to continually maintain the power system requirements.

Predictability

Participation in the NEM dispatch process involves provision of various types of measurement (e.g. near real-time telemetry) and forecasting data across numerous timeframes that are obtained mostly from information submitted through the bidding process.

However, existing electricity wholesale market frameworks such as central scheduling and dispatch, are not fit-for-purpose for integrating DER into the wholesale market at scale because they do not support visibility or scheduling of DER in the NEM. There are currently no VPPs with small-scale DER participating in the wholesale energy market.

Dispatchability

Progress has been made on the two key elements of dispatchability with regard to DER:

- There is broad consensus that DOEs are an effective mechanism for DNSPs to coordinate DER so that distribution network power flows remain within secure limits. AEMO will also require visibility of DOEs, discussed in the next section.
- DER has been shown, in Project EDGE and many other projects, to be operable and dispatchable. Responding to DOEs is a form of operability, and this chapter goes into greater detail on the performance of VPPs in Project EDGE acting as scheduled resources.

A key hypothesis of Project EDGE is that VPPs would need to make material investments to develop key capabilities required for scheduling (full dispatchability in wholesale dispatch). Progressive wholesale participation through phases such as visibility only, self-dispatch and scheduling could support VPP participation while they develop these capabilities through staged investment over time.

184 AEMO. 2017, Visibility of Distributed Energy Resources: Future Power System Security Program, sections 3.3 and 3.4. https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/aemo-fpss-program-visibility-of-der.pdf?la=en#:~:text=Without%20visibility%20of%20how%20these,or%20multiple%20credible%20contingency%20events.

AEMO. 2022. Scheduled Lite: Draft High Level Design, section 2.2. https://aemo.com.au/-/media/files/initiatives/scheduled-lite/consultation-paper-draft-high-level-design-for-scheduled-lite.pdf?la=en

Information captured by Deloitte Access Economics in consultation with AEMO for the Project EDGE CBA.

185 For further context of minimum system load conditions, see AEMO. 2022, Smart Meter Backstop Mechanism Capability Trial: Phase 2 Evaluation Report, section 3.4 and 3.4.5. https://aemo.com.au/-/media/files/initiatives/der/2022/smart-meter-backstop-mechanism-capability-trial-report-phase-2.pdf?la=en

186 AEMO. 2017, Visibility of Distributed Energy Resources: Future Power System Security Program, sections 3.3 and 3.4. https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/aemo-fpss-program-visibility-of-der.pdf?la=en#:~:text=Without%20visibility%20of%20how%20these,or%20multiple%20credible%20contingency%20events

187 EY. 2023, Project EDGE: Technology and Cybersecurity Assessment, Appendix A. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

INSIGHTS

Progressive wholesale participation: the self-dispatch stepping-stone

Project EDGE tested a 'self-dispatch' model using the 'energy fixed loading' field in the existing wholesale market bid-file to act as a stepping-stone towards dispatchability.

Self-dispatch enabled passive market participation, where bids and offer quantities (without prices) submitted would not influence clearing price calculations but would act as a forecast of performance that is visible to AEMO. Aggregators would therefore be price takers and would self-nominate their portfolio dispatch targets.

This stepping-stone could give aggregators the flexibility and control to set their own targets to test and learn with relatively small portfolios (in terms of portfolio capacity) of DER while progressively developing more sophisticated systems to be able to determine bids at many price points and with confidence to meet these forecasts if dispatched by AEMO.

A 'self-dispatch' model between visibility and dispatchability models could act as another stepping-stone to allow VPPs to develop full dispatchability capabilities.

5.1.2.4 Visibility of DOEs that can coordinate DER output for sites not participating in a VPP

The implementation of DOEs not require all DER to participate in a VPP (although there are greater system benefits, and as a result greater benefits for all consumers, from higher DER participation in VPPs. See the discussion in Chapter 3).

However, DOE implementation could mean all new DER connected to the distribution network are allocated a DOE. For example, in South Australia, new rooftop PV systems installed as part of the Smarter Homes Program must be capable of remotely updating and enacting flexible export limits.[188]

Having visibility of the DOEs that coordinate DER not participating in VPPs would facilitate the operation of a secure system by providing visibility of the potential shift in power flows resulting from DER output responding to DOEs that are not otherwise visible.

Industry will need to consider how AEMO could receive visibility of these DOEs. The DER data hub, discussed further in Chapter 6 is a potentially efficient mechanism for achieving this.

5.1.2.5 Visibility of coordinated DER commitments made off-market

Before reaching a material scale that may require participation in the wholesale market (see section 5.3.2), aggregators could provide off-market services such as local NSS, discussed in Chapter 7.

These VPPs, if operating off-market, would not be required to provide forecasts to AEMO. However, to operate a secure system in a high DER future, AEMO would need aggregated visibility of such off-market commitments as the volumes traded scale up.

Project EDGE did not explore this topic, but it is a consideration for industry to investigate further. One possible mechanism to enable this visibility without forecasts could be a DER data hub (see section 5.1.2.6 and Chapter 6).

Aggregators participating in the wholesale market, and therefore required to provide forecasts or bi-directional offers to AEMO, would need to include the quantity for their NSS commitments in their bi-directional offers.

In terms of visibility for secure system and market operations, AEMO may not require the granular detail of the quantity committed to network support services within a bi-directional offer. Rather, it may simply require that the total capacity committed by an aggregator portfolio is reflected within its forecasts or bids to AEMO.

188 Government of South Australia. N.d., Dynamic Export Limits Requirement. https://www.energymining.sa.gov.au/industry/modern-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes/dynamic-export-limits-requirement

AEMO would also need to understand the relationship between the aggregator's portfolio and the distribution network and transmission network interfaces, such as the Transmission Node Identifier (TNI) code. In the event VPPs are providing local network services at scale but not yet providing forecasts or bids to AEMO, an appropriate mechanism (and materiality threshold) for AEMO to gain visibility of these coordinated DER commitments will need to be identified. Two considerations are requiring a forecast of aggregators and AEMO having visibility of DNSP NSS arming/event trigger signals communicated through the DER data hub.

5.1.2.6 A DER data hub as the enabler of visibility

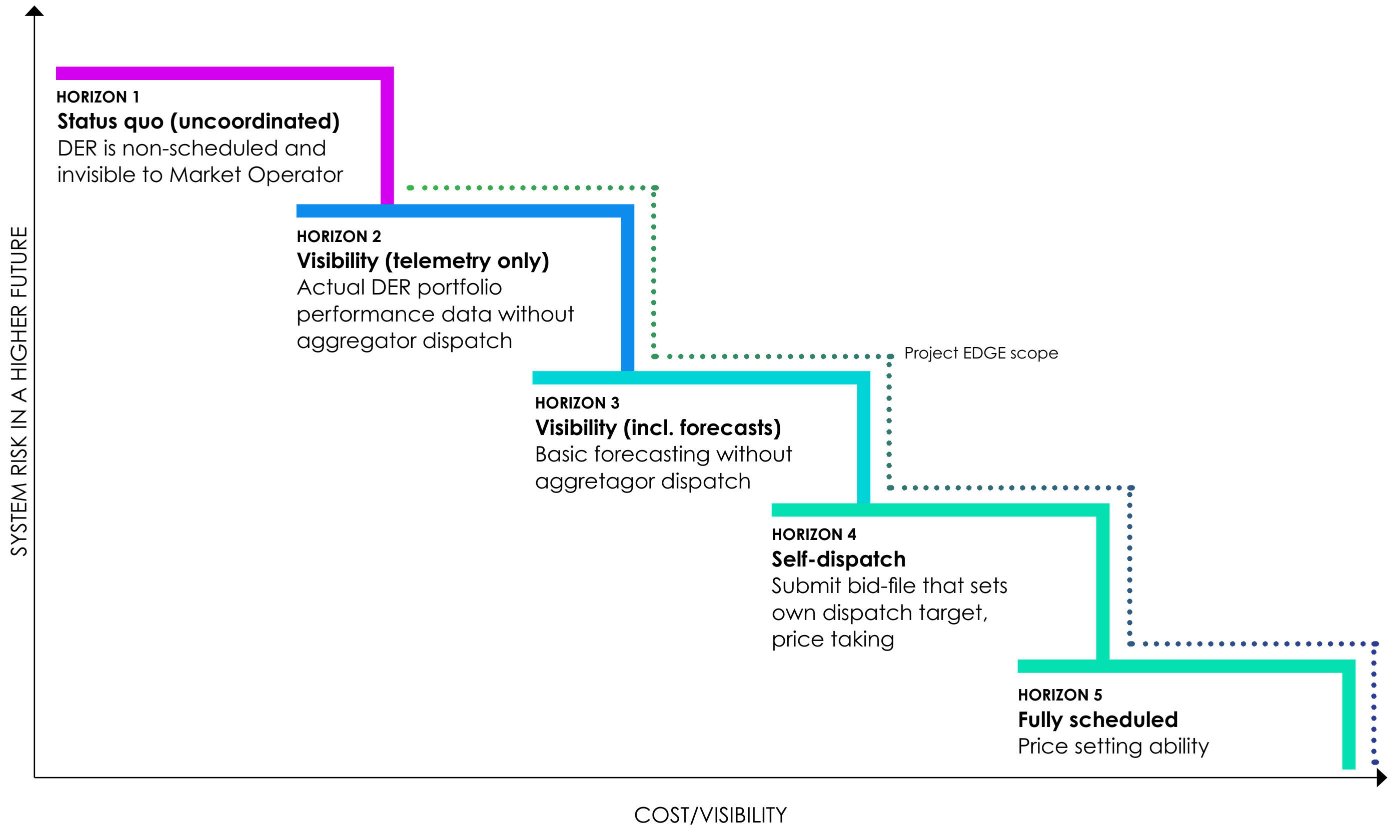
The visibility discussed above and coordinating DER to support ongoing power system requirements will require large volumes of data to be exchanged across many industry actors and stakeholders. Chapter 6 discusses a DER data hub approach as a scalable and long-term approach for DER data exchange compared with current point-to-point approaches between industry actors. Under a data hub approach, AEMO could gain visibility of DOEs and off-market DER commitments at the same time as DNSPs and aggregators exchange this data.

5.2 Approach

To understand efficient and effective approaches to integrate DER into electricity markets, Project EDGE tested progressive levels of participation of coordinated DER in the wholesale market.

Three active aggregators participated in off-market field tests exploring different 'modes' reflecting progressive levels of wholesale market participation. The stepping-stone approach tested in Project EDGE is illustrated in Figure 50.

Figure 50 | Stepping-stone approach to wholesale market participation tested in Project EDGE



Field tests were undertaken 24/7, aligned with existing NEM hours, bidding close for a trading day[189] and dispatch intervals (but off-market) from the end of April 2022 to the end of March 2023.

Additionally, a number of real-world scenarios were tested throughout the field trial to test aggregator capabilities under more challenging market conditions that could arise (based on historical market events and the aggregators' forecast and actual wholesale prices).

The aggregators' performance was analysed using field trial data to understand how they executed key capabilities that would be required to participate in the wholesale market as scheduled resources (see section 5.3).

The objective of each data analysis activity and the methodology used were agreed through a collaborative process with subject matter experts from AEMO, AusNet and Mondo. The two other active aggregators were also invited to participate during these sessions, and an overview of the agreed approach was played back to them for feedback. Additional sessions were held to share preliminary results from the analysis for feedback and agreement on next steps for analysis.

Data analysis was supported by weekly discussions with each of the three active aggregators to understand context and operational conditions and strategies that may have contributed to the data analysis results.

To complement the field trial analysis, discussions were held with AGL, a Project EDGE research participant, to discuss field test data results and compare observed behaviour with AGL's experience as an in-market retail VPP operator.

5.3 Findings

This section is structured to set out the insights and evidence that support a progressive approach to wholesale market participation for DER, divided into three over-arching factors:

- **Moving beyond the self-consumption only model, this will take time** (section 5.3.1)
  DER consumers' priorities for self-consumption are not always aligned with system needs, and self-consumption only models mostly ignore revenue opportunities from price signals (positive or negative).
- It will take time for consumers to trust that VPPs can utilise their DER to deliver services back to the power system, and still maintain high levels of personal utility. This is explored further in Chapter 3. This trust is beginning to develop with more customers enrolling in VPPs, but with an expectation that they will be 'better off overall'.
- The three active aggregators participating in Project EDGE adopted an approach of self-consumption plus external services (e.g. electricity wholesale market services and B2B via local NSS), in which DER mostly responds to system needs only for sufficiently strong price signals (positive or negative).
- **Aggregator capability development can be rapid but needs appropriate incentives** (section 5.3.2)
  It takes aggregators time to improve their performance to the level of sophistication required to become dispatchable resources that do not compromise system security.
- Project EDGE, and the VPP Demonstration projects,190 have shown it is possible for aggregators to deliver wholesale services. As discussed above, a stepping-stone approach that builds capabilities for wholesale participation in stages would allow industry to mature VPP capability to more sophisticated levels over time.

  These insights regarding a stepping-stone approach can continue to inform the development of the proposed approach for the Scheduled Lite mechanism.[191]

189 In the NEM, bidding closes at AEST 12:30 the day before a trading day (Day -1, where the trading day is Day 0). Bids must contain quantities for each band, and prices for each band. Band prices for Day 0 cannot be changed after 1230.

AEMO. 2023, Spot Market Operations Timetable, p 5 https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/spot-market-operations-timetable.pdf?la=en

Similarly, in Project EDGE, aggregator price bands were firmed and locked at 1230 a day before the trading day. After that time, an aggregator could only change the quantity but not the price bands.

Project EDGE. 2023, Project EDGE Bi-directional Offer (Boffer) for Wholesale Energy: Options for aggregators to participate in off-market wholesale dispatch – high level design document, p 9. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-technical-specifications

190 AEMO. N.d., Virtual Power Plant (VPP) Demonstrations. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations

191 AEMC. N.d., Integrating price-responsive resources into the NEM. https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

- **Applicability of scheduled resource operating requirements to DER** (section 5.3.3)
  The obligations on scheduled resources in the NEM and the sophisticated capabilities required to meet expected performance standards are wide-ranging. Some of these obligations should be applied equally to DER, but there may be a case for DER to meet alternative performance standards for some obligations.

5.3.1 Moving beyond the self-consumption only model, this will take time

Currently, the primary driver of DER behaviour is consumers' preference for self-consumption, which could limit the potential value delivered for DER customers and consumers as a whole

A self-consumption only model is where an aggregator prioritises the use of each customer's DER devices for self-consumption of energy generated at the customer's site (e.g. from rooftop PV). Under this model, revenue opportunities from price signals (positive or negative) are largely ignored.

Consumer research conducted by Deakin University (see Chapter 2 for a detailed discussion), and the experience of aggregators participating in the trial, demonstrates aggregator behaviour is primarily driven by their customers' preference for self-consumption.

This preference for self-consumption is linked to consumers' motivations for investing in DER and participating in VPPs. Deakin's research suggests that chief among these are the reduction of electricity bills and greater energy self-reliance.

The objective of a self-consumption only model is to minimise net grid imports at the NMI (to directly reduce customers' consumption component of the electricity bills received from their electricity retailer). Most aggregators have designed their products and systems around this primary objective.

This provides aggregators with a starting point to develop capabilities along the stepping-stone approach. However, aggregators beginning with this model should consider 'future-proofing' their architecture so that if they choose to progress to a self-consumption plus other services model, their systems can be enhanced to enable alternative operating approaches.

5.3.1.1 Progressing to price-responsiveness

A natural progression that adds value but maintains self-consumption as a key objective would be the introduction of price-responsiveness at price points the aggregator has calculated to provide sufficient value to the customer. If the market price goes beyond these price points, the aggregator responds and bids accordingly based on its available portfolio capacity.

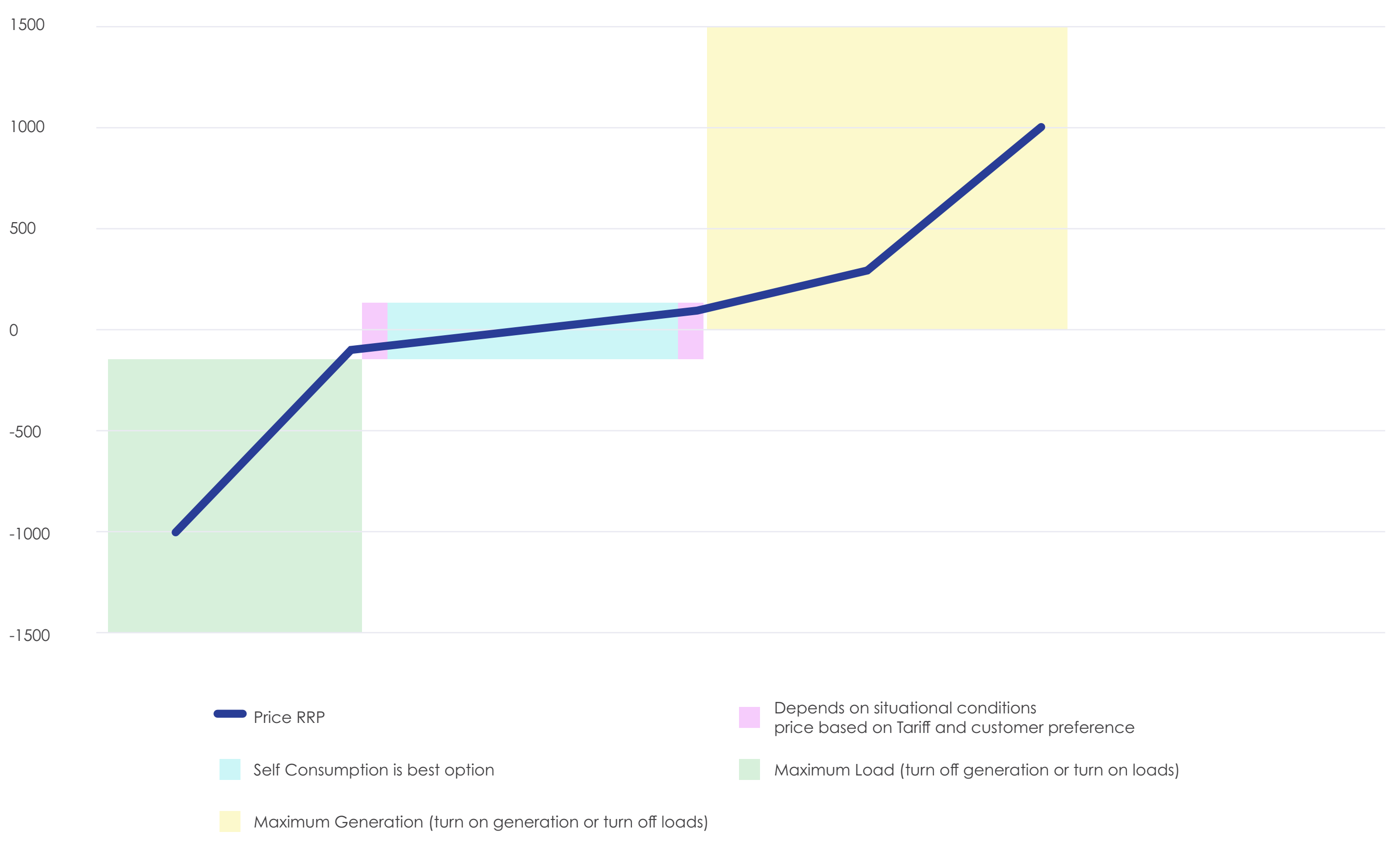
The three active aggregators in the Project EDGE field trial set 'value thresholds' (price points192), which are book-end, extreme price bands at which they would respond to market price signals over self-consumption, subject to fleet capacity.

Moving beyond self-consumption only models would require aggregators to provide clear information to customers about the potential additional value that could be achieved by branching out to models of self-consumption plus other services (see section 2.3.3 for a discussion on Deakin's findings on strategies to motivate additional coordinated VPP activity).

Figure 51 illustrates the potential opportunities (in the wholesale electricity market) if aggregator bidding behaviour is more price-responsive.

192 AEMC. N.d., Integrating price-responsive resources into the NEM. https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

Figure 51 | Conceptual representation of relationship between volume bid and price depending on the potential VPP behaviour during non-benign wholesale prices



Note: Bids and offers are provided in price-quantity pairs and actual behaviour and value may not be linear. This figure is intended to provide a conceptual representation of the relationship between the quantity bid at different price points. Under a self-consumption only model, an aggregator would not bid any quantity into the extreme price bands and would therefore limit potentially lucrative revenue.

Performance in field tests throughout the Project EDGE trial (see section 5.3.2) showed that aggregator behaviour during benign wholesale prices (-$50 to $300/MWh) focused on optimising individual sites for self-consumption. Aggregators noted that, based on their customers' preferences, set price band parameters were used to deliver the self-consumption product (the turquoise band in Figure 51).

Outside of those set price bands, aggregators could re-bid to increase the quantity offered in higher price bands to maximise revenue from extreme high prices (yellow band in the Figure 51) or extreme low prices (green band in the Figure 51) and prepare as necessary (e.g. by charging batteries ahead of forecast extreme high prices and delaying charging until forecast extreme low prices).

This would enable aggregators to earn and share greater financial returns with their customers (from market and/or business-to-business services, such as supporting retailers or DNSPs). However, it means that aggregators would not provide self-consumption to all customers during these events.

Aggregators would need to communicate with customers to assure them that, during certain times, there is greater value in not self-consuming during these uncommon events, and ensure the customer receives net benefit in the long-term.

The Project EDGE field trial and Deakin University customer research found that setting customer expectations on the amount of DER control activity at enrolment was crucial. The trial also identified that meeting varying customer preferences for non-self-consumption responses could be assisted by aggregators developing capability to cycle the sites that respond for any given event. Section 5.3.2.2 summarises the field test results, showing how aggregators performed during the market events that were tested.

Aggregators also indicated a need to develop more sophisticated models for tracking the customer benefits available from self-consumption versus cumulative benefit of active participation in energy services markets

5.3.1.2 Service-based stepping-stones

In addition to capability-based stepping-stones, there are many potential service-based stepping-stones (new revenue streams that support capability development) for an aggregator between a self-consumption model and becoming fully scheduled resources.

These service-based stepping-stones could provide larger revenue pools and include participation in FCAS, RERT and off-market business-to-business services (such as retailer hedging or local network support services).

Given the costs (discussed in detail in the next section) of developing sophisticated VPP capabilities for wholesale market participation, a service-based stepping-stone approach could enable aggregators to access other revenue opportunities while they progressively develop their customer bases and technical capabilities over time. This would help aggregators and VPPs build towards participation in the wholesale scheduling and dispatch process.

Exposure to the wholesale market

Another key factor affecting the ability of aggregators to move beyond self-consumption models at scale is that the regulatory framework does not allow aggregators of mass market DER to benefit directly from wholesale market exposure unless via a retailer ('Market Customer'). Under current arrangements, where the VPP is not operated by a retailer, this requires aggregators to form hedging agreements with retailers.

In this negotiation, retailers may have a stronger position than the aggregator. This is because retailers have the direct customer relationship with the customer in the market as the financially responsible market participant (FRMP)[193] for the customer's premises and are the entities taking on the market exposure risk. Examples of hedging include discharging a battery during a high price event to reduce the retailer's exposure to high wholesale prices and charging during a low negative price event to reduce the retailer's exposure to paying negative prices for customer solar export.

Mechanisms that enable aggregators to become the FRMP for a customer's controllable resources (such as the 'unlocking CER benefits through flexible trading' rule change proposal) would allow aggregators to operate without needing to enter into an agreement with a retailer to access value.

Reform initiatives that open up wholesale market access directly to non-retailer aggregators of mass market DER present additional revenue opportunities that could facilitate VPPs achieving scale.

INSIGHTS

A service-based stepping-stone approach

Building social licence and customer trust to move beyond self-consumption only models will enable VPPs to utilise customers' DER to deliver more services. A service-based stepping-stone approach can enable VPPs to access more revenue streams while developing more sophisticated capabilities that build towards wholesale market participation.

193 The FRMP is the energy industry term for the actor, identified in respect of a connection point, responsible for dealing with AEMO in relation to a specific load

5.3.2 Aggregator performance and capability development

Aggregators need time to develop sophisticated technical capabilities for market participation

Many of the functions and capabilities tested in Project EDGE have been forward looking; for instance, testing how VPPs might interact in the energy markets as scheduled resources.

A key learning is that the costs for aggregators to develop the capabilities to be scheduled in the current dispatch process, and ongoing operational costs, would materially reduce the value that VPPs can share with customers, unless they have achieved material scale.

As described above, a service-based stepping-stone approach would enable VPPs to access new revenue opportunities to facilitate investment in more sophisticated technical capabilities.

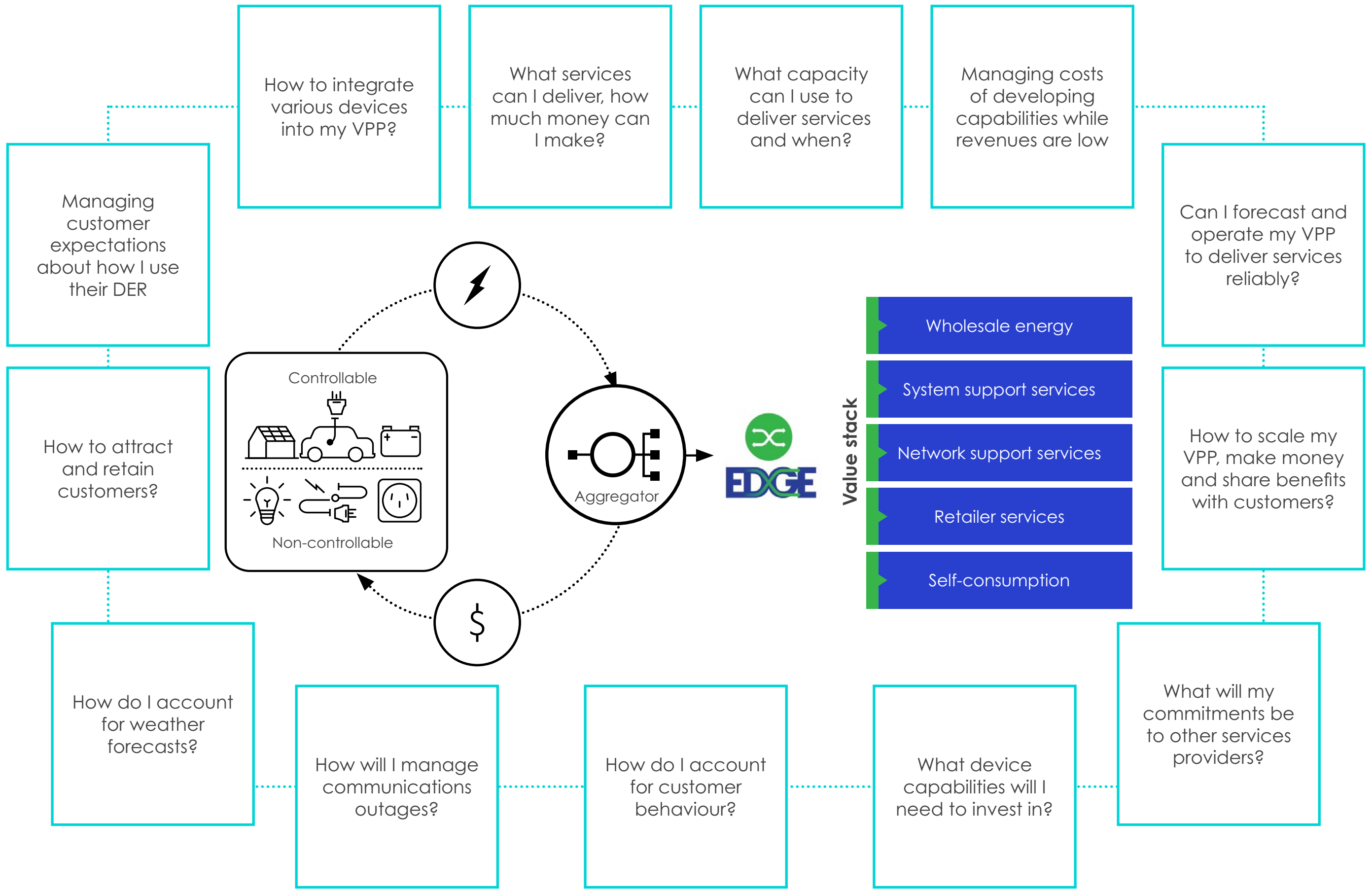
Additionally, market requirements suitable for coordinated DER (see section 5.3.3) should be developed in a way that balances management of power system risks with the commercial feasibility of implementing solutions for DER to mitigate those risks (see, for example, the CBA's findings on how data exchange approaches can reduce integration costs for aggregators in section 3.3.2).

Access to greater revenue opportunities and the ability to provide services at low cost could help aggregators generate more value and scale. The main capabilities aggregators need to develop are:

- Reliable forecasting capabilities (section 5.3.2.1).
- Bidding and re-bidding behaviour (section 5.3.2.2).
- Provision of operational data (section 5.3.2.3).
- Coordinating DER as a portfolio to meet dispatch target conformance, including linear ramping (sections 5.3.2.4 and 5.3.2.5).
- DOE conformance (section 5.3.2.6).
- Communications and compensatory controls (section 5.3.2.7).
- An understanding of market requirements for scheduled resources (section 5.3.2.8).
- Service co-optimisation and value stacking (section 5.3.2.9).

Developing these capabilities, along with related considerations such as investment and operational costs, access to revenue opportunities to value stack and managing customer expectations, are key factors that aggregators will need to consider. The breadth of complexities that VPPs need to consider are illustrated in Figure 52.

Figure 52 | Considerations for aggregators



Quantity definition/location for bidding and forecasting

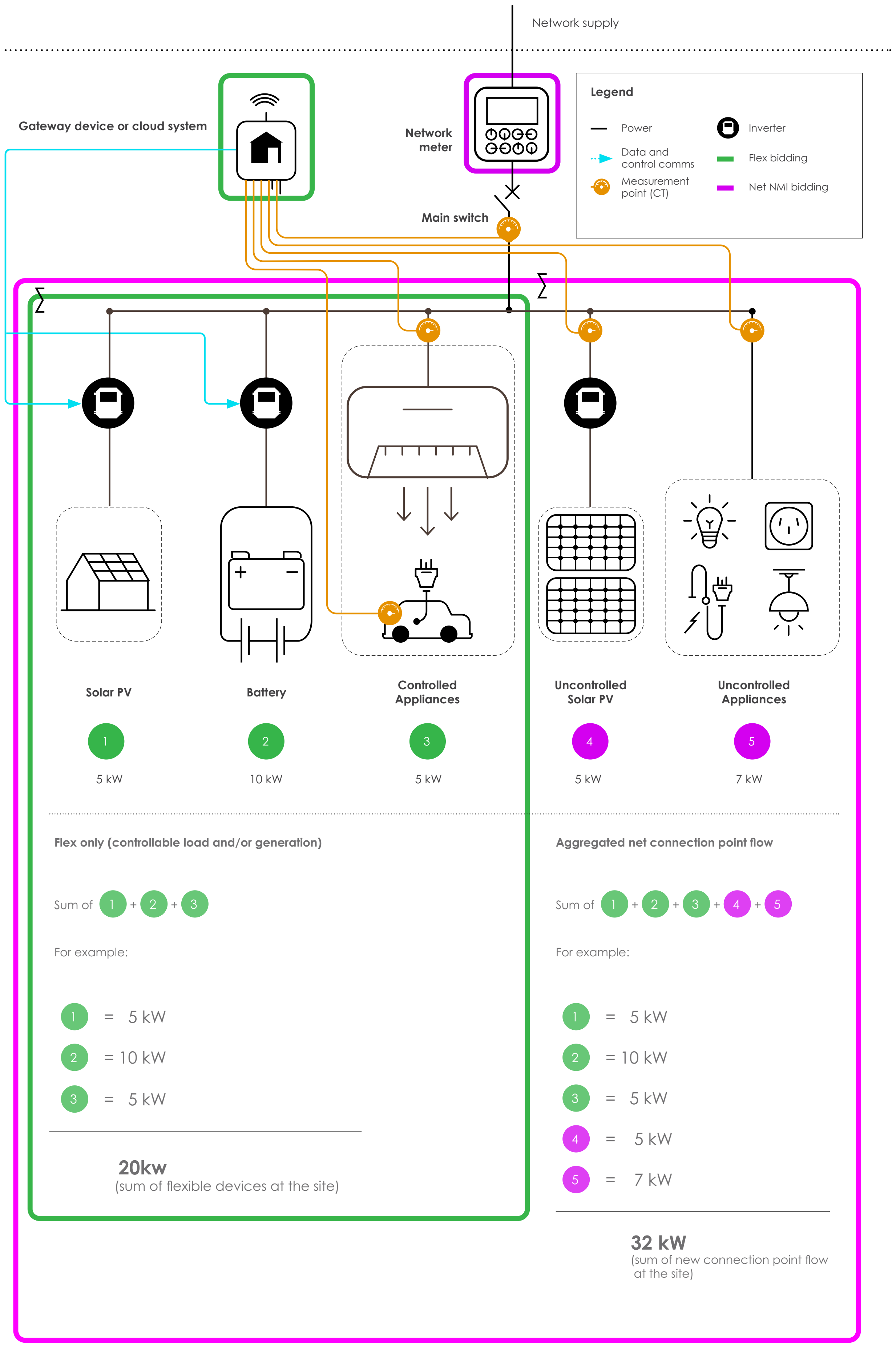
Before exploring aggregator capabilities in detail, it is important to understand that Project EDGE tested two different definitions/locations for the quantity figure that feeds into the bidding and forecasting process. AEMO uses forward information in the bid file to inform various operational forecasting models (e.g. pre-dispatch forecasts).

The two definitions tested are referred as Net NMI bidding and Flex bidding,[194] explained below.

194 See Project EDGE: Bi-Directional Offer (Boffer) for Wholesale Energy in the Appendices, for example, in constructing bids, and for an overview of DUID telemetry data measurements.

AEMO. 2023, Project EDGE Bi-directional Offer (Boffer) for Wholesale Energy: Options for aggregators to participate in off-market wholesale dispatch – high level design document. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-technical-specifications

Figure 53 | Illustration of the two bidding quantity definitions field tested



Net NMI bidding: A Net NMI bid represents the sum of net connection point flows across the aggregator's registered portfolio of NMIs. It is represented by all the devices in the larger purple box. It includes all controllable devices (1, 2 and 3), and uncontrollable devices (4 and 5). It is measured at the NMI (the network meter in the small purple box).

Under Net NMI bidding, separation of controlled and uncontrolled capacity is not visible to AEMO in the bi-directional offer or the associated NMI telemetry.

Flex bidding: A Flex bid represents the sum[195] of controllable devices (load and/or generation, not individual devices) across the aggregator's registered portfolio of NMIs. It is represented by devices in the larger green box. It includes only controllable devices (1, 2 and 3). It is measured at the real or virtual measurement point of controllable devices (the device or cloud[196] in the smaller green box of Figure 53).

Under Flex bidding, the bi-directional offer and telemetry provides visibility of all price-responsive, controlled capacity.

5.3.2.1 Reliable forecasting capabilities

Developing accurate forecasting capabilities is a key challenge aggregators will need to meet

Forecasts of coordinated DER generation and consumption at various price points over operational horizons will be critical to provide visibility for AEMO to maintain operational forecasting accuracy and broader power system requirements (discussed in section 5.1.2.1).

Reliable forecasts also contribute to wholesale price formation and operational market efficiencies and reduce the frequency of emergency interventions by AEMO.[197]

Field test analysis compared forecasting accuracy under Net NMI bidding and Flex bidding (as outlined above). Field test data forecasting error was analysed across different time horizons leading up to dispatch (from 48 hours ahead to 5 minutes ahead, the 'final bi-directional offer') for each aggregator portfolio.

As expected, forecasting 5 minutes ahead of the dispatch interval had the highest accuracy (lowest error). This is because the aggregators used short-term forecasting models in the last two hours (but after the submission of the 2 hours ahead bi-directional offer) leading up to dispatch. The short-term forecasting models blend real-time data with historical data. Real-time data provides better accuracy compared to solely using historical data in the longer-term forecasts.

Forecast accuracy was not materially different for forecast horizons between 2 and 24 hours ahead – multi hour ahead forecasting is more challenging as it is more exposed to uncertainty from variables such as consumer response to weather and PV generation (cloud cover).

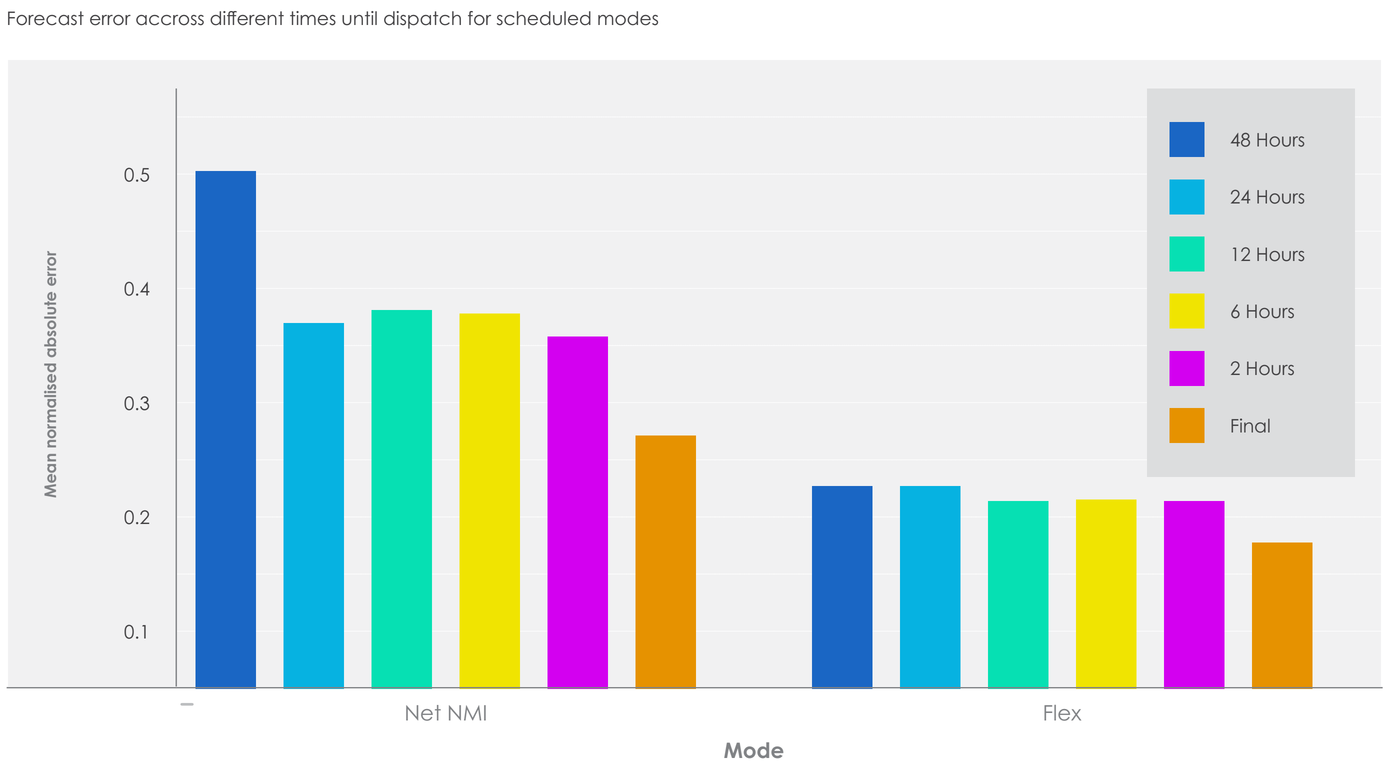
Figure 54 shows the mean normalised absolute error (MNAE) in kW at the 48 hours (dark blue), 24 hours (light blue), 12 hours (green), 6 hours (yellow), 2 hours (magenta), and final (orange) bi-directional offer. The absolute error was normalised by portfolio capacity to enable comparison among the aggregators.

195 The total, and where controllable load and controllable generation together within the green box offset each other. For example, solar PV (controllable device 1) absorbed by the battery (controllable device 2) does not show.

196 Project EDGE trialled retailer and non-retailer aggregator business models. Aggregators used either gateway devices or direct cloud integration to coordinate their customers' DER and gather measurement data. These data feeds were correlated with smart meter data to establish confidence in their usefulness for analysis. In real life, measurement devices need to comply with the NEM metering framework and be National Measurement Institute pattern approved so that the market can have confidence in measurement accuracy.

197 AEMO. 2023, Electricity Rule Change Proposal: Scheduled Lite January 2023, p 5. https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

Figure 54 | Forecasting accuracy across different time horizons for all field tests where aggregators were acting as scheduled resources (receiving dispatch instructions)



Note that 'Final' in the graph means 5 minutes before the next dispatch interval.

A 'target' MNAE would be 0, which would indicate complete and accurate forecasts of capacity from 48 hours to dispatch. It is important to note that uncertainty exists, therefore 'target' forecasting with 0% error will never be attainable.

The figure shows that:

- Under Net NMI bidding (on the left), MNAE reduces over the time horizons as aggregators gain greater certainty in their fleet's capacity. The accuracy of forecasts changes by 50% over 48 hours.
- Under Flex bidding (on the right), there is less change and accuracy is more consistent across the time horizons, and also reduces over time.

Overall, Flex bidding resulted in more accurate forecasting across all time horizons.

The aggregators used the same forecasting models (albeit progressively enhanced throughout the trial) regardless of the bidding quantity definition because they prioritised self-consumption most of the time.

The results suggest the improvement in accuracy with Flex bidding was due to the bidding quantity definition. Uncontrolled load is the key driver of higher forecasting errors in Net NMI bidding. The absence of uncontrolled load in Flex bidding means an aggregator can remove some forecasting risk.

Variability remains in controllable rooftop PV due to weather and when solar is not generating in the evening and batteries are supplying uncontrolled load, the Flex generation bid is effectively the remaining portfolio capacity after supplying the uncontrolled load.

Regardless of whether an aggregator is prioritising self-consumption or progressing to providing an electricity service, the absence of uncontrolled load in Flex bidding provides an inherent advantage for managing dispatch non-conformance risk (discussed in section 5.3.2.2) and in managing wholesale price risk (discussed in section 5.3.2.4) because conformance is evaluated only for devices directly under the aggregator's control.

INSIGHTS

Field trial findings on the Flex bidding approach

Evidence suggests that provision of VPP forecasts through a Flex bidding approach should be more accurate, and the alignment of Flex bidding to AEMO's operational forecasting approaches should improve the accuracy of AEMO's forecasts as DER participation increases.

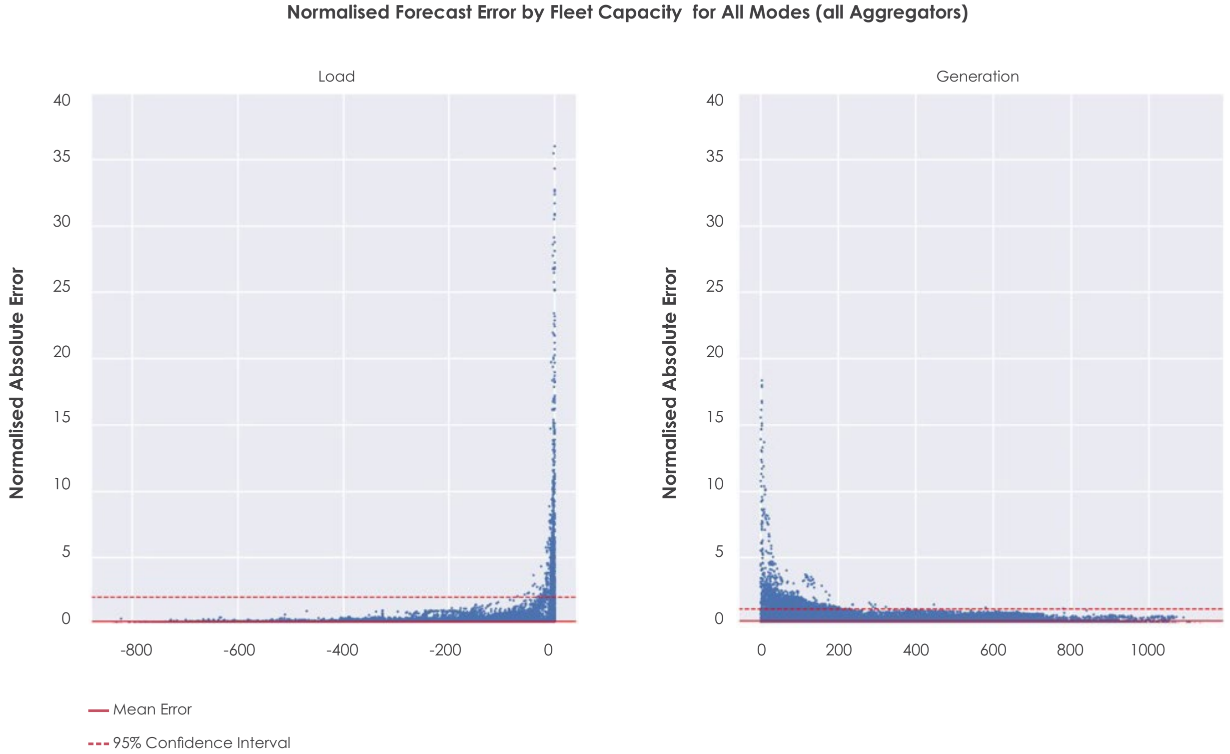
Forecasting accuracy improves as portfolio capacity increases

Field test results showed that fleet size needs to reach materiality thresholds to reduce normalised forecasting error.

Figure 55 shows the normalised forecasting error by fleet capacity across all field tests (including both Net NMI and Flex bidding quantity definitions). The graph on the left shows load forecasting error; the graph on the right shows generation forecasting error over the 5-minute (final bi-directional offer) forecast.

As maximum available capacity (kW) increases, there is an observable exponential decrease in error. It should be noted that forecasting models also improved over time. Nonetheless, aggregators noted that, overall, accuracy does increase as capacity increases.

Figure 55 | Forecasting error by fleet capacity across all field tests



Forecasting error was also compared between Net NMI bidding and Flex bidding.

Figure 56 shows results for Net NMI bidding. The same exponential decrease in error as fleet capacity increases is observed. Load forecasting shows a significant improvement as maximum available capacity increased. This shows the benefits of diversity in load.

Figure 56 | Forecasting error by fleet capacity for Net NMI bidding field tests

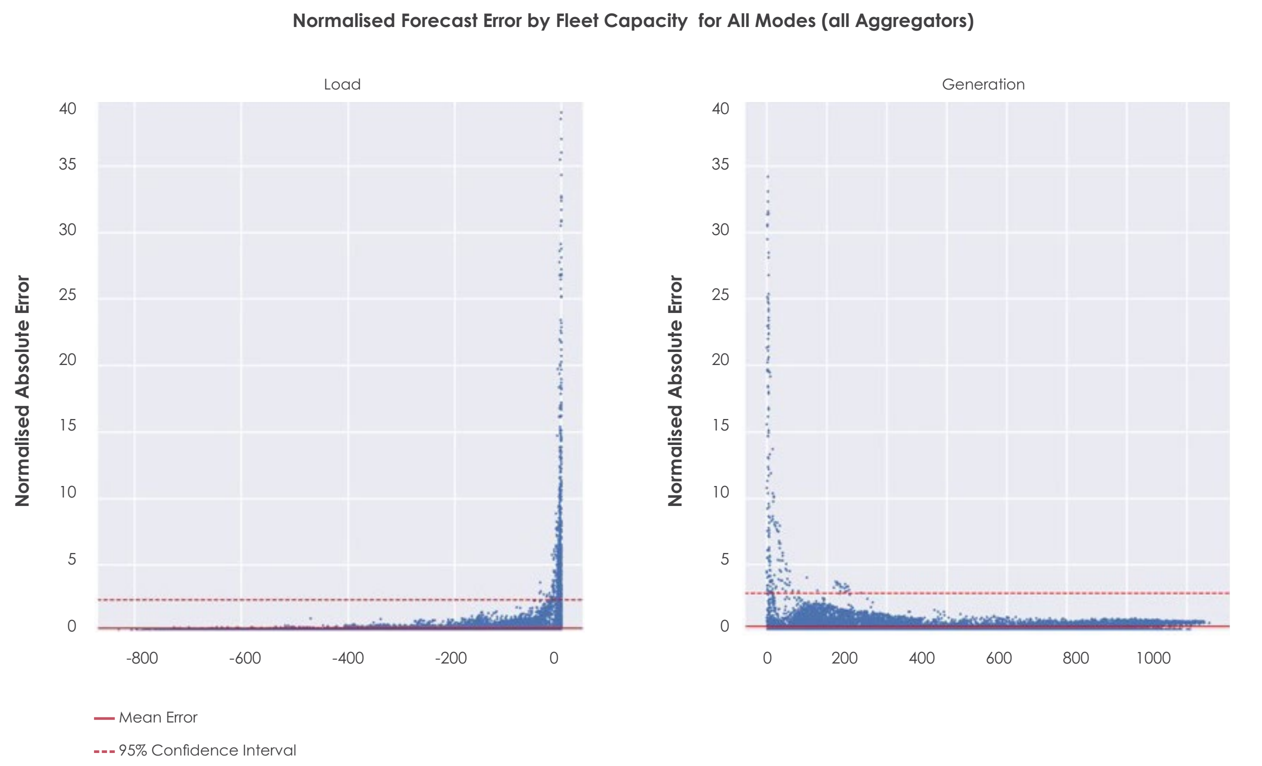
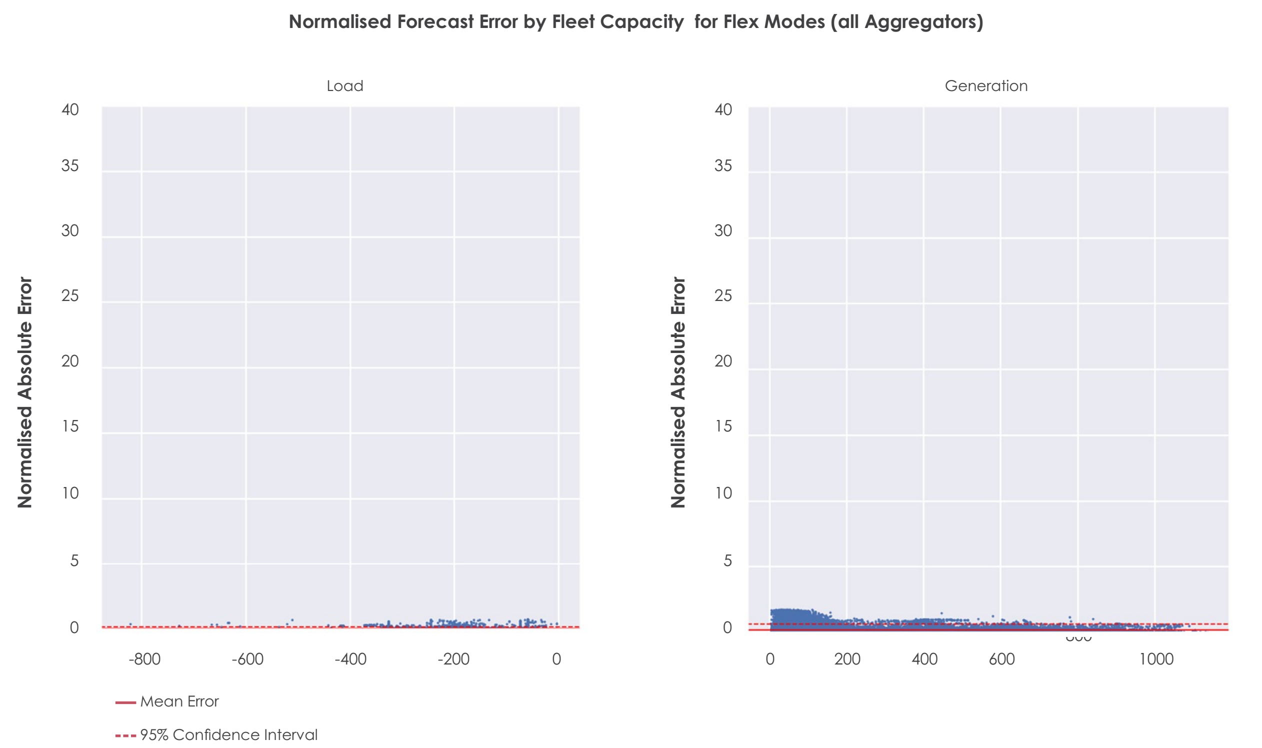


Figure 57 shows the results for Flex bidding. Results for load forecasting (analysing 5-minute 'final' bi-directional offer) do not show a noticeable difference as fleet capacity increases. This is because, generally, loads in Flex occurred when batteries were charging from the grid. This behaviour was predictable and less challenging to forecast. However, for generation forecasting, error does decrease as fleet capacity increases.

Figure 57 | Forecasting error by fleet capacity for Flex bidding field tests



While forecasting error decreases as fleet capacity increases under both bidding quantity definitions, the results comparing the two also show normalised absolute forecasting error is higher under Net NMI bidding, with lower fleet capacity compared to Flex bidding.

This strongly suggests forecasts for smaller capacity fleets may be more accurate under Flex bidding. It also strongly suggests that producing forecasts at more granular levels is extremely challenging and that there is likely a limit to what can be achieved by aggregators.

While the results show that aggregators can improve forecasting capabilities over time as they update and refine algorithms and have access to more data and customer sites, the nature of DER means forecasting will never be 100 % accurate. This should be considered when contemplating performance requirements for coordinated DER at high scale.

INSIGHTS

Fleet size impacts on forecasting performance

Field test results from the Project EDGE trial show that fleet size is an important factor in reducing normalised forecasting error, and that forecasts for smaller capacity fleets may be more accurate under Flex bidding.

5.3.2.2 Bidding and re-bidding behaviour

Aggregators will need capabilities to identify and adopt bidding and re-bidding strategies suitable for market participation

- Participating VPPs in Project EDGE operated as though they were in the wholesale market by:
- Monitoring forecasts and live Victorian wholesale prices from the NEM to inform their bidding
- Bidding their portfolio every 5 minutes using up to 20 price/quantity (kW) pairs across a 48 hour rolling window of 5-minute market dispatch intervals
- Receiving and acting on dispatch instructions sent out by AEMO.

Submitting their bid files also served as the aggregators' price-responsive forecasts in Project EDGE. This forecast gives AEMO visibility of potential coordinated electrical generation or load, a critical input to its key role of balancing of supply and demand at all times (discussed in section 5.1).

Project EDGE tested both bid quantity definitions: net NMI bidding and Flex bidding.

Net NMI bidding

Net NMI bidding occurs currently in the NEM, as large-scale generator bids are measured as 'sent out generation'. The NER defines this, in relation to a generating unit, as the amount of electricity supplied to the transmission or distribution network at its connection point.[198]

This means these generators must account for the auxiliary load required to operate their power plants, as well as losses on their private powerlines that connect them to the main grid at the abovementioned connection point (meter), which sends telemetry to AEMO for the central dispatch process.

198 NER, Chapter 10: NER Glossary. https://energy-rules.aemc.gov.au/ner/477

There are important differences in the nature of VPPs as a dispatchable resource compared to large-scale generation when it comes to auxiliary/non-controllable loads:

1 Variability: Large power plant auxiliary loads are known and relatively stable compared with the uncontrolled load in the homes and businesses of aggregator customers, which can vary greatly with weather and customer behaviour.

2 Materiality: Auxiliary loads represent a very small portion of a generator's output whereas the proportion of uncontrolled customer load compared to controllable DER in an aggregator's portfolio can vary greatly and its volume can exceed that of the controllable resource.

3 Risk: Uncontrolled load within VPPs is an essential service (lights, amenities and even life support) integral to people's livelihoods and is protected under law.[199] Generator auxiliary loads are important for a generator to run their commercial business but are not considered an essential service.[200]

Aggregators participating as a scheduled resource in Net NMI (including uncontrolled load) would be responsible for bidding a quantity that represents each customer's whole site, as unexpected changes in passive consumption may compromise the level of flexibility available to the aggregator to manage its portfolio and meet dispatch instructions.

To manage these factors when operating Net NMI bidding, aggregators may need to maintain larger margins of headroom, which can reduce the efficient utilisation of the aggregator's available capacity, although great fleet size and appliance types may also provide diversity benefits for net NMI bidding to reduce the margin for error.

Flex bidding

Flex bidding may offer a relatively simple way to reduce some of the challenges for VPPs bidding into the wholesale market.

Some bidding challenges would remain since VPPs operating PV self-consumption as a primary objective would still need to monitor and respond to changes in uncontrolled loads, which would impact available capacity for flexible loads. This was reflected in the experience of the Project EDGE aggregators.

However, dispatch conformance is likely to be easier under Flex bidding (discussed further in section 5.3.2.4).

Impact on AEMO's real-time operations and operational forecasting.

The implications of Net NMI bidding and Flex bidding on AEMO's real-time operations and operational forecasting can be summarised as:

- **Real time operations:** AEMO is required to balance supply and demand at all times and to develop contingency plans for possible power system disturbances in real time. This requires confidence that the load or generation called upon in dispatch will respond accurately.
- Flex bidding and dispatch of DER provides additional confidence to the market operator as only controllable DER is forecast and bid (e.g. the total MW bid is controllable by the aggregator), compared to Net NMI where a portion of the DER forecast and bid is uncontrollable and hence may not respond as expected.
- This is important in normal market operations for economic efficiency and particularly important to maintaining overarching system security when AEMO issues instructions to direct resources during operational challenges.
- **Operational forecasting:** The separation of controllable and uncontrollable resources under Flex bidding allows aligns with AEMO's existing operational forecasting models and is expected to result in more accurate demand forecasts, leading to a more efficient and cost-effective wholesale market.

  Under Net NMI, this separation does not occur, and demand forecasts must account for the unknown uncontrollable DER component. As AEMO can only take this into consideration at an abstracted level, meaning that operational forecasting under Net NMI would be less accurate than under Flex bidding.

199 See for example, section 45(3) of the National Energy Retail Law that requires the AER to consider the principle that the supply of energy is an essential service for residential customers when it is approving a customer hardship policy. Part 7 of the National Energy Retail Rules prescribes obligations on retailers regarding the registration and de-registration of customers' premises where a person residing or intending to reside requires life support equipment. The rules also include a prohibition on the de-energisation of a premises registered under Part 7 as having life support equipment.

200 AEMO. 2019, Fact Sheet - Connecting and Energising a Generating System Prior to Registration. https://aemo.com.au/-/media/files/electricity/nem/participant_information/new-participants/fact-sheet-nem-connecting-and-energising-generators-before-registration.pdf

Greater accuracy in AEMO's operational forecasts with Flex bidding can deliver benefits such as:

- Forecast reserve requirements may be less.
- FCAS requirements, and associated costs, may be less.
- More accurate planning for contingency actions in response to power system disturbances.

To obtain the necessary visibility and controllability required to continue to operate dispatch in a way that maintains network security and reliability, AEMO would need either:

- Flex bidding, whereby the resources bid into the aggregation can be assumed to be controllable
- Net NMI bidding, but with further data to provide the visibility of the flexible portion.

Importantly, the bidding quantity definitions of Net NMI and Flex described in this chapter were defined for the purpose of testing within Project EDGE, which was an off-market trial. Consideration would need to be given to how these bidding approaches would be applied in terms of in-market registration, participation and settlement.

Reform initiatives currently underway, including 'unlocking CER benefits through flexible trading',[201] are expected to provide enduring frameworks for unbundling flexible resources from passive resources to facilitate the reward of their flexibility and provide visibility through independent market participation – similar in concept to Flex bidding participation within existing market frameworks as tested in Project EDGE (discussed at the beginning of this section).

Bidding in good faith

A key consideration of the field test results was the concept of 'bidding in good faith'. Clause 3.8.22A of the current NER provides that offers, bids and rebids must not be false or misleading.[202]

Under this rule, the making of a dispatch offer, dispatch bid or rebid is deemed to represent that the offer, bid or rebid will not be changed unless the generator or market participant becomes aware of a change in the material conditions and circumstances on which the offer, bid or rebid is based.

The practice of deliberate late re-bidding can decrease market confidence in forward information about the market, including AEMO's pre-dispatch forecast. Additionally, price formation in the market requires more accurate forecasts over a longer time horizon than 5 minutes to 1 hour (see the next section for results from the Project EDGE field trial relating to aggregator re-bidding behaviour).

Therefore, late rebids by coordinated DER might disadvantage other market participants. Existing generators' offers are deemed a representation of their willingness to provide supply at the prices specified.[203] As noted above, they also have an obligation under the NER to make any rebid to vary an offer to supply the market as soon as practicable after a material change in conditions. However, generators can re-bid on the basis of a change in their expectations, provided it occurs as soon as practicable.

The nature of DER means a portfolio is subject to changes in weather[204] and uncontrolled load. Because it comprises many small sites operating across public internet, it is also subject to communications losses. This combination of factors can make the available capacity of DER portfolios dynamic at times.

201 AEMC. N.d., Unlocking CER benefits through flexible trading. https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading;

AEMC. N.d., Integrating energy storage systems into the NEM. https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

202 As included in the latest electronically available version as of May 2023.

203 AEMC. 2015, Biding in good faith. https://www.aemc.gov.au/sites/default/files/content/8d8ee814-aa4e-46bd-ba2f-addef9fa08a2/Bidding-in-good-faith-information-sheet-final-determination.pdf

204 Since DER aggregators are subject to both changes in load and weather. Semi-scheduled generators such as wind and solar farms already participate in the Australian Wind Energy Forecasting Systems (AWEFS) and solar equivalent (ASEFS) that help to provide a common understanding of weather variability to improve the overall efficiency of NEM dispatch.

AEMO. N.d., Australian Wind Energy Forecasting System. https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-wind-energy-forecasting-system; AEMO. N.d., Australian Solar Energy Forecasting System. https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system

INSIGHTS

Industry considerations of 5-minute rebid implications

Project EDGE enforced the same NEM rule regarding bidding closure; however re-bidding every 5 mins was necessary due to the nature of DER. Accordingly, industry will need to consider the broader implications of 5-minute rebids on other market participants, and compatibility with existing rules that bids and rebids must not be misleading.

Bidding behaviour during Project EDGE field trial

In addition to aggregator forecast and dispatch responses, behaviour and data from the Project EDGE field trial was analysed to understand aggregator bidding and re-bidding responses.

Results from the field trial showed that bidding behaviour in benign market conditions, without materially high or low wholesale prices, was similar among aggregators and was driven by their customers' preferences for self-consumption.

Figure 58 shows typical bidding behaviour. It is an example from one aggregator (but indicative of general trends) on a spring day and under Net NMI bidding.

Figure 58 | Example of typical BAU bidding behaviour by aggreagators consistent with a 'self-consumption' load profile

The dark purple line represents the average dispatch profile for the field trial. The DOE during this example allowed plenty of export capacity. The 6- and 2-hour bids and offers (orange and pink respectively) are almost identical. Both follow the average self-consumption BAU profile across the entire field trial (dark purple line) where spot price forecasts range from $400 to -$100 (top graph, light purple and green lines).

Net NMI bids leveraged DER reaction to uncontrolled customer load (on a high generation day). 'Excess' generation and load were offered 5 minutes before the next interval (final bi-directional offer (brown line)) and was closely followed by fleet telemetry (dark blue shaded area for load and light blue shaded area for generation)).

This practice, while not exclusive to DER, may have an adverse effect on market efficiency by not being included in wholesale price formation or AEMO's operational demand forecasts.

Bidding behaviour in the field trial also reflected differing event 'materiality thresholds' per aggregator, which influenced the active pursuit of market opportunities.

In Figure 58, a low price event (-$100/MW) was forecast 1 hour ahead (light blue line on the top graph, marked 'A'). The figure shows the aggregator:

- Did not prepare its fleet for –$100 (A) (it did not release battery capacity ahead of the forecast low price so that its fleet had capacity to charge during the low price intervals)
- Appears to have prepared for $500 (marked 'B') (the aggregator consumed load to store energy ahead of the forecast high price so that it could export during the high price intervals).

This reflects that the decision to prepare can be driven by time, price and/or fleet capacity. It can also be customer-driven with expectations set at enrolment with the VPP (for example, if customers sign-up for limited intervention outside self-consumption).

Differing risk positions, customer agreements and costs per aggregator will influence price thresholds for providing market services over customer self-consumption.

Re-bidding behaviour

Analysis of field trial results showed there were instances where the three active aggregators were not actively adjusting their bids and offers as part of market price formation. This indicates a trend that aggregators applied a 'set and forget' strategy for bidding.

Another driver for this behaviour was that the aggregators focused on a customer self-consumption model. This self-consumption model resulted in aggregators offering quantities only in the extreme ends of the bids and offers. These quantities typically required the aggregator to calculate the remaining capacity, following estimates on the self-consumption of load and generation.

Project EDGE hosted a number of discussions with aggregators to explore responses to a range of wholesale prices over time (negative sustained and high peak prices) and unexpected price events (short notice spikes and extreme drops).

These discussions highlighted that customers had preferences about how their DER were being used, which meant the aggregator needed to maintain any market responses within these preferences. At times, this limited the responses from aggregators to bid at the extreme price events.

Figure 59, Figure 60, and Figure 61 show that the aggregators did not rebid with new values, and therefore were not actively bidding in the market at all times.

A summary of the aggregated distinct values per bid band across each day was divided by the number of dispatch intervals per day (288). This calculation created a metric, which was then related to the quantity of unique numbers in the previously submitted bids and offers for each dispatch interval.

DEFINITION

Unique bid and re-bid

A **unique bid** is a bid with a different quantity value in the bid band compared with the previous bid.

A **re-bid** refers to how frequently the aggregator re-submitted a bid.

There was no correlation between the days when an aggregator is actively bidding (indicated by a higher number of unique bids) and the days when an aggregator is re-bidding often. Noting that when an aggregator is bidding more often, it would be expected to result in more unique values.

This suggests a largely 'set and forget' approach to bidding.

Bidding strategies could undermine dispatch conformance. Aggregators that do not actively re-bid but submit 'set and forget' price band bids could risk missed revenue opportunities and non-conformance enforcement actions. Aggregators should be actively re-bidding to reflect quantities that are achievable or desirable.

The results show that none of aggregators used all 20 price bands for bidding; rather, they used the extreme price bands. There were many time periods where they were not actively bidding.

It is expected that aggregator re-bidding behaviour would change as the sophistication of their related technical capabilities improves.

Figure 59 | Aggregator A: summary per day, per price band, the number of unique values with submitted bids and offers

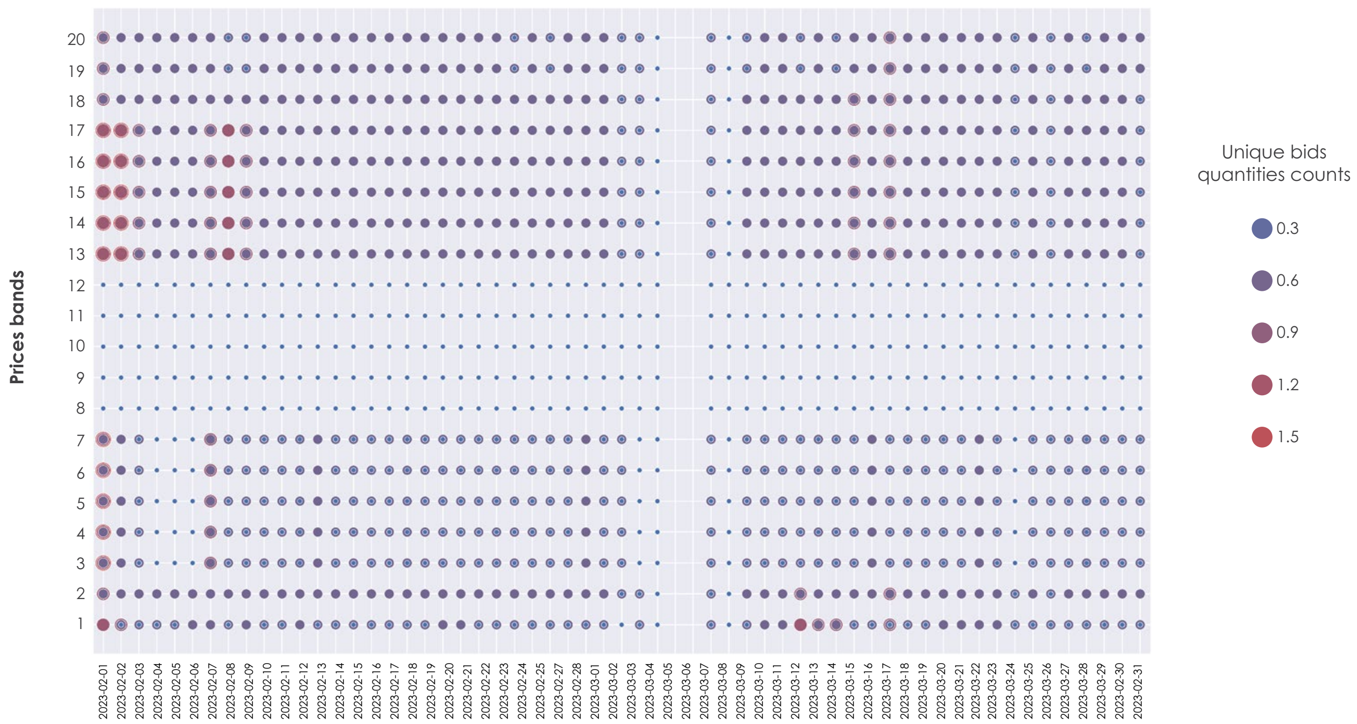


Figure 59 shows that Aggregator A was the least active bidding aggregator, as shown by the predominance of the metric related to the lower number of unique numbers in the previously submitted bids and offers for each dispatch interval (smaller blue and purple circles)

Figure 60 | Aggregator B: summary per day, per price band, the number of unique values with submitted bids and offers

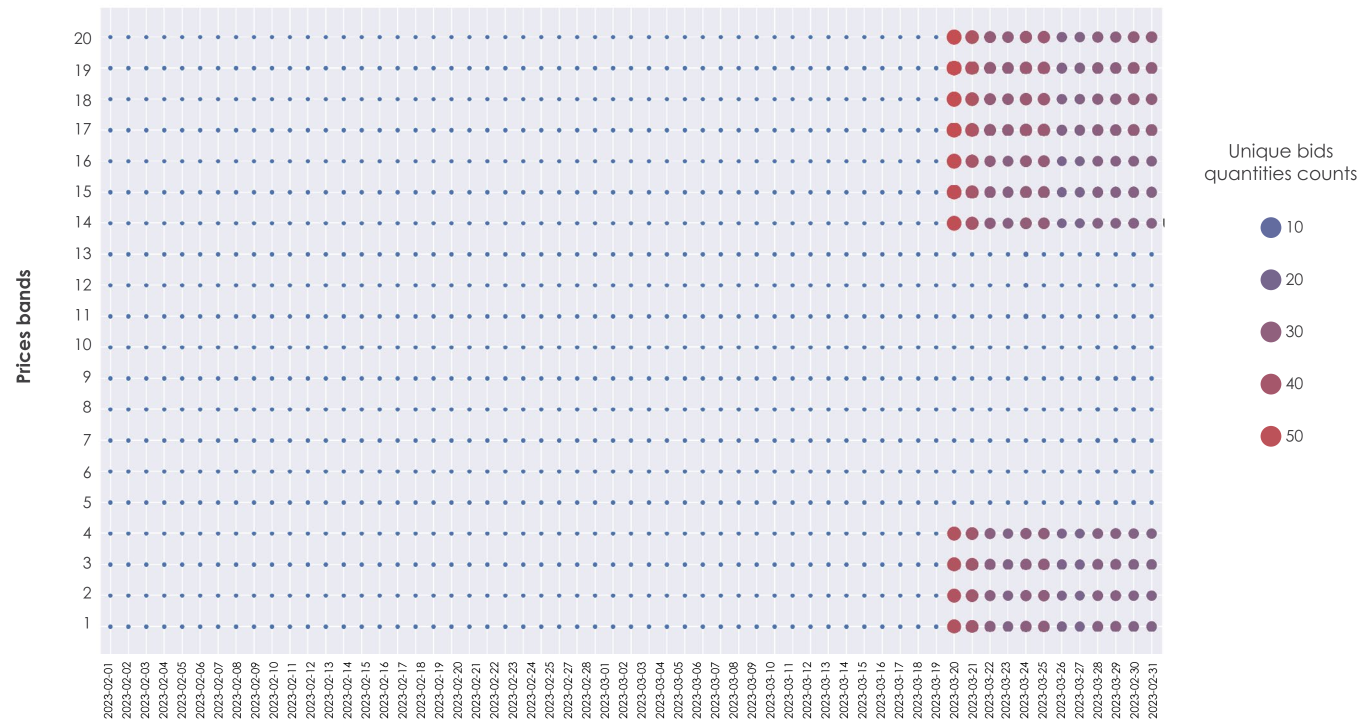


Figure 60 shows that Aggregator B was the most active re-bidder (number of bids with unique bidding quantities) during the days it was actually re-bidding: a total of 12 days within the two months of analysis. This is shown by the predominance of the metric related to a large number of unique numbers (on the days it was re-bidding) in the previously submitted bids and offers for each dispatch interval (larger purple and red circles).

Figure 61 | Aggregator C: summary per day, per price band, the number of unique values with submitted bids and offers

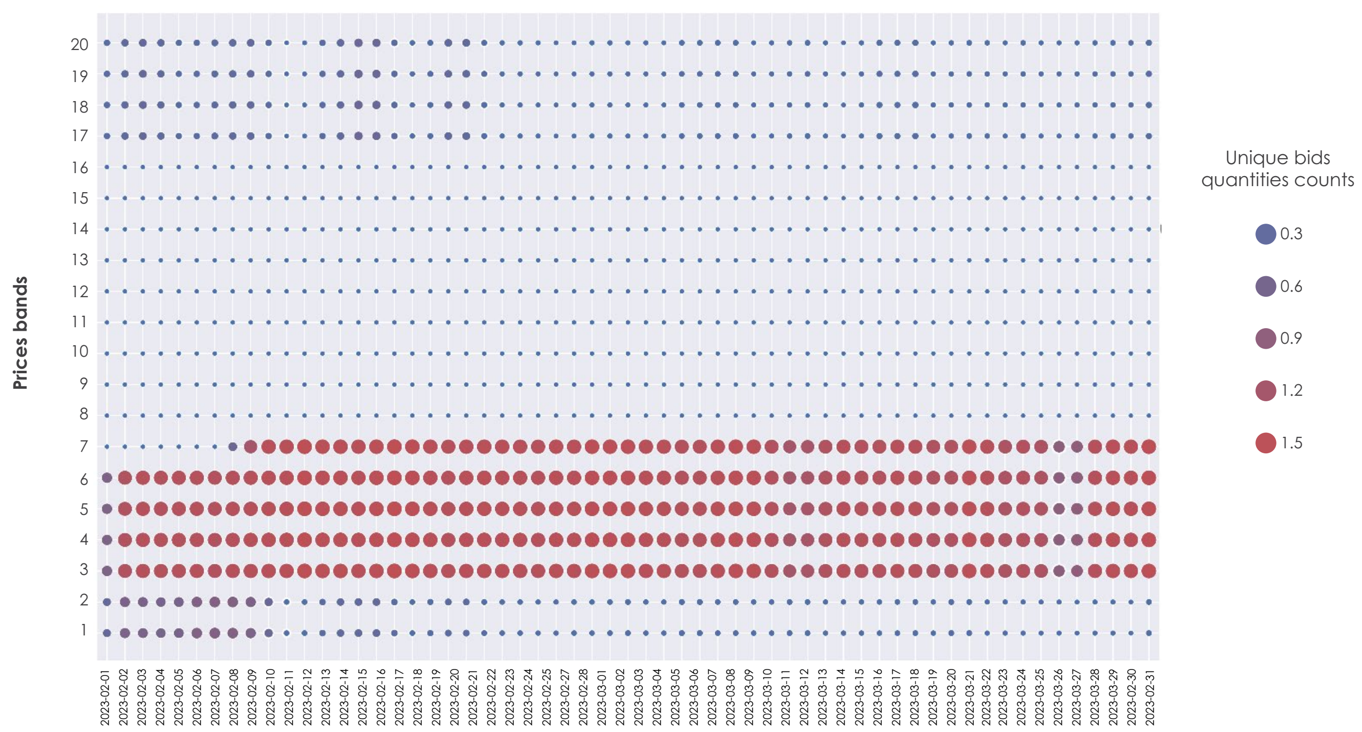


Figure 61 shows that Aggregator C was mainly using price bands 1 through to 7 – the load part of the bi-directional offer – shown by the predominance of the metric related to a large number of unique numbers in the previously submitted bids and offers for each dispatch interval in these price bands (larger purple and red circles).

This behaviour was due to a miscalculation in controlled generation confirmed by the aggregator. Controlled generation should be composed of both PV and battery generation. However, only the battery generation was included. There is some activity in the extreme generation bands (17 through 20) which shows this aggregator's fleet of batteries would only discharge in extreme price events.

CASE STUDY
Energy price arbitrage in high impact market events

The Project EDGE field trial tested a broad range of price events using historical NEM event prices (forecast and actual) to test aggregator performance in infrequent, high impact market price events that occur in the NEM, but that were not guaranteed to occur naturally during the field trial.

These forecast historical event prices were delivered to the aggregators via the same price data exchange channel as live NEM price forecasts, so that aggregators were unaware of when an event was being tested.

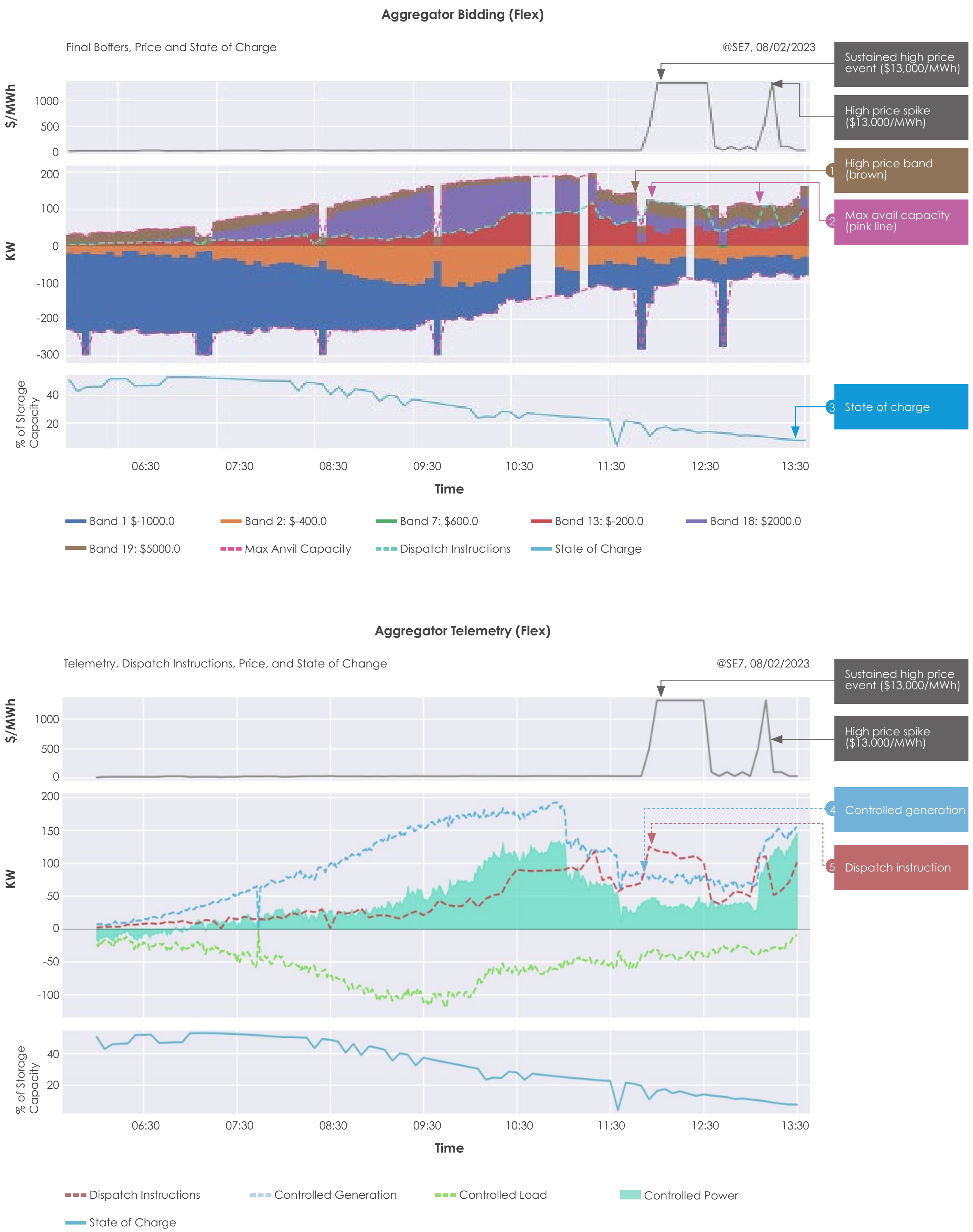
Figure 62 shows the potential implications of a 'set and forget' approach to re-bidding.

The event field tested a sustained high price during midday, followed by a spike.

The sustained high price spike was $13,000/MWh from 12:00 until 12:30. After this time, prices dropped to just above $0/MWh (still positive). This was followed by a high price spike ($13,000/MWh) at 13:00 for one interval before the price dropped back down.

This event was visible to aggregators in the forecast prices they received at least 8 hours ahead of time so they could prepare.

Figure 62 | Testing of aggregator response to a sustained high price during midday followed by a spike



The top graph shows the aggregator's (Flex) bidding response to the price event. The bottom graph shows the aggregator's telemetry response to the price event.

Box 1 shows the distribution of bid bands does not change. The quantity bid in the high price band (brown) remains relatively consistent. The expected response was a significant increase of quantity in this brown band, made available by the fleet preparing for the forecast high price by charging batteries from the grid in the morning. This is consistent with the observed short-term forecasting trends discussed in section 5.3.2.1 (generally similar at all time horizons until a less than 2-hour lead time).

Participating aggregators noted that failure to respond to price events was typically due to three potential factors:

- DOE constraints
- Customer agreements (e.g. limiting the number of times an aggregator can control a customer's device)
- Equipment status (e.g. insufficient storage capacity).

Box 3 shows the battery stage of charge for the aggregator's fleet. The near depleted storage capacity from 11:30 to 13:30 suggests the aggregator's response may be due to equipment status or a decision not to prepare for forecast high prices by charging batteries in the morning (around 08:00).

The latter reason would be due to customer preferences for self-consumption because they do not trust that they would be 'better off overall' from a different use of their DER (discussed in Chapter 2).

In the bottom graph, Box 4 shows the controlled generation (blue dashed line) decreased significantly before and for the duration of the high price event.

Box 5 highlights a ~80kW shortfall between the dispatch instruction (dashed red line) and the actual portfolio performance (DER controlled power, turquoise shaded area) for the duration of the event.

Box 2 shows the aggregator did not re-bid during the sustained high price event. This is reflected in the maximum available capacity not being revised down after the aggregator could not achieve the dispatch instruction at 11:45 hours.

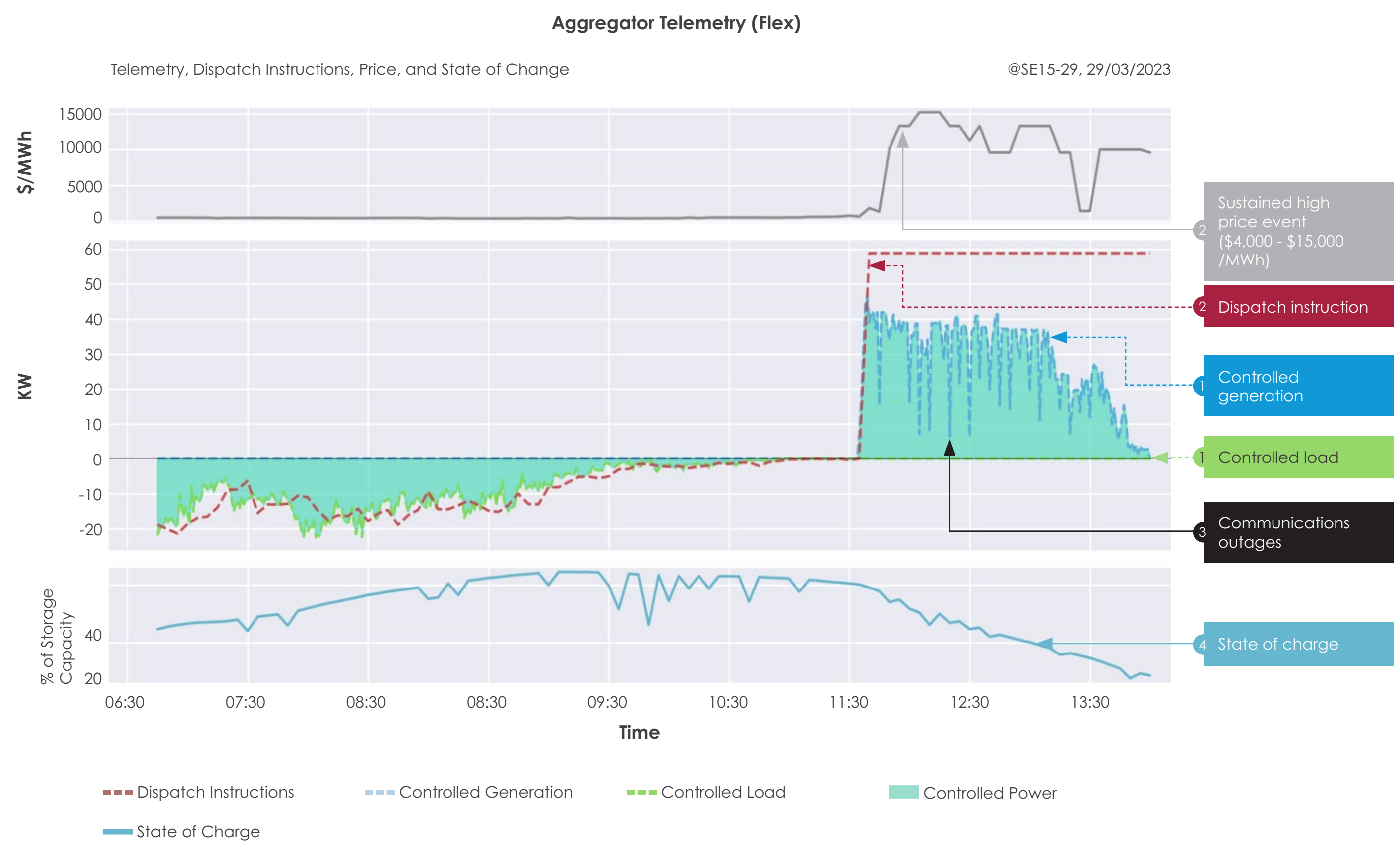
Contributing factors to dispatch non-conformance in this scenario were:

- The reduction in generation output (noted in box 4)
- The controlled load (green line) remaining at –50kW. The aggregator could have switched off the controlled load to get closer to the dispatch instruction and earn $13,000/MWh for the additional capacity released. The value of aggregators being able to control both load and generation (technically and with appropriate customer permissions) is discussed in section 5.3.2.8.
- The portfolio's storage capacity was insufficient to discharge more generation (noting there was some capacity available but perhaps not enough in the context of preserving some for self-consumption).
- The bi-directional offer seems to have reflected the fleet's total capacity but not the capacity the aggregator was willing or able respond with. This shows a lack of headroom in bids for extremely high or negative prices. Aggregators perform better in terms of absolute dispatch conformance error with headroom, which is usually available during day-time self-consumption operations where coordinated DER generation capacity far exceeds uncontrolled load
- Failure to re-bid following a dispatch non-conformance in the previous interval, so that the next interval receives a more achievable dispatch target.

Figure 63 provides an example of an important aggregator capability to develop: re-bidding in response to battery state of charge.

This tested event used historical clearing and forecast prices leading up to the 2022 market suspension event (administered pricing cap event). There were sustained high prices during the early evening of $4,000/MWh to $15,000/MWh from 18:50 until 21:00.

Figure 63 | Testing of aggregator response to ta sustained high price during early evening



Box 1 shows the aggregator controlled batteries to discharge (controlled generation) in an attempt to conform with the dispatch instructions (the red dashed line – box 2).

This was a short-notice event. Only the 5-minute forecast provided an indicator to the aggregator of the price event. This example shows that the aggregator in the field trial demonstrated capabilities to respond quickly to volatility (as the aggregator did not prepare for this event).

Box 3 shows sharp saw-toothing in the portfolio telemetry (turquoise shaded area), which indicates a communications outage. This may have been a contributing factor to non-conformance.

Another factor contributing to non-conformance was battery state of charge forecasting error combined with this being a sustained event (almost 2 hours). The state of charge was not at, or near, the maximum required at the start of the event (box 4) to be able to support the offered capacity for the entire event duration.

Additionally, high price band quantities and/or maximum available generation were not re-bid lower in response to not meeting dispatch instructions (red dashed line). This trend was also observed in the example discussed in section 5.3.2.8.

5.3.2.3 Provision of operational data

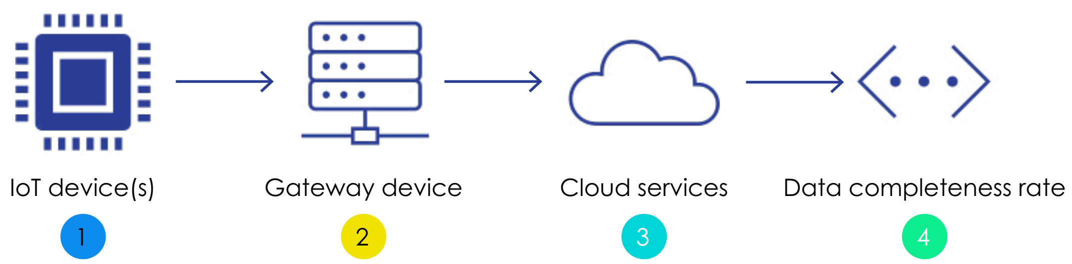
Capabilities to support accurate and complete high-fidelity telemetry data are costly and take time to develop

Strong data communications and analysis is a foundation for VPPs to access revenue opportunities in electricity markets. However, VPPs need to be commercially viable, or have sufficient upfront capital, to invest in these capabilities.

This creates a 'chicken versus egg' situation: standardisation to minimise the costs of coordinating DER could improve the commercial viability of VPPs but future obligations on performance standards will have to balance the need to manage power system risks with the commercial feasibility for aggregators to comply with the standards.

Analysis of overall completeness of telemetry data found a high data completeness rate across all three aggregators participating in the Project EDGE field trial. Figure 64 shows the telemetry data lifecycle and the average latency for each communication step, and DUID telemetry data completeness rate.

Figure 64 | Aggregator telemetry data collection and transmission process and overall completeness



	Granularity	Batch update frequency	Latency	Fleet completeness rate
Aggregator A	5 seconds	1 minute	10–15 seconds	90%
Aggregator B	1 minute	1 minute	16 seconds	95%
Aggregator C	10 seconds	30 seconds	10–15 seconds	95%

The analysis explored:

- **Granularity (column 1):** how often the measurements were taken. Using the example of Aggregator A, its devices take measurements every 5 seconds.
- **Batch update frequency (column 2):** how often the telemetry file was transmitted from the local device to the cloud service or aggregator's systems. This represents a form of buffering or 'intentional' latency (how long the aggregator's devices wait to batch the measurements taken). Using Aggregator A as an example, its on-site devices query the IoT device every 1 minute to batch the measurements taken in column 1.
- **Latency (column 3):** general lag in time to transmit the data from the on-site device (batched in column 2) to the aggregator's cloud services or systems, ready to go to the recipient (in the trial, this was AEMO via the data exchange hub).
- **Fleet completeness (column 4 - % sites):** at the end of this cycle, the percentage completeness of the fleet represented in the data (i.e. the percentage of NMIs in the fleet that provided complete data; for example, 9 out of 10 NMIs equals 90% completeness).
- **Portfolio telemetry transmission frequency (columns 1 to 3):** how frequently whole of portfolio telemetry files were submitted to the data exchange hub without any delay built into the process (column 2).

High frequency portfolio telemetry transmission analysis

This section summarises analysis of the average completion rate for each active aggregator over a one week period (compared to Figure 64 which shows the results for the duration of the field trial).

Analysis was based on timestamps received from IoT devices to the aggregator's cloud before being packaged into DUID telemetry and sent to the DER data hub (the process in column 3 in Figure 64).

The objective of the analysis was to determine the relationship between DUID telemetry data 'completeness' and frequency of transmission from the aggregator to AEMO in terms of how much of the aggregator's portfolio's DER capacity was reflected in the DUID telemetry.

The analysis looked at each aggregator's average completion rate for each 1-minute period over one week, as well as the average delay (in seconds) to achieve 100% fleet completeness.

All three active aggregators noted that power (capacity) completeness (the percentage of DER capacity) is almost 1:1 with fleet completeness (column 4 in Figure 64). This trend may differ in a portfolio where a few large sites provide a significant portion of aggregator capacity, in which case additional communications sophistication may warrant investment.

Figure 65 provides the results for Aggregator A. The average delay for Aggregator A to reach 95% fleet completeness was less than 2 seconds. Across the duration of the field trial, the average delay was 10-15 seconds, as shown in column 3 of Figure 64. The average delay to reach 100% fleet completeness was between 4 and 6 seconds, with no material variance across the time of day.

Figure 65 | Average delay (seconds) for Aggregator A to reach 100% fleet completeness

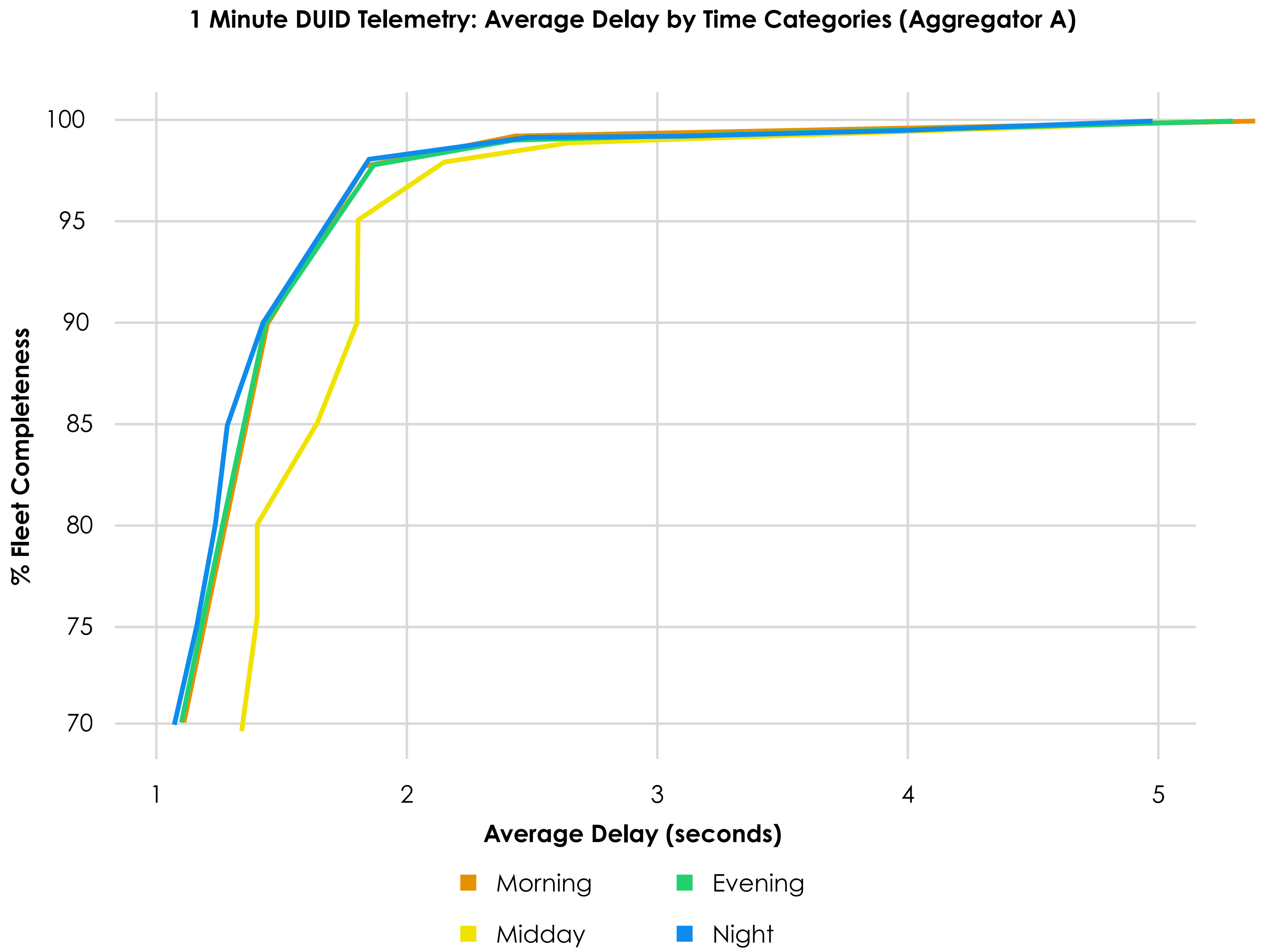
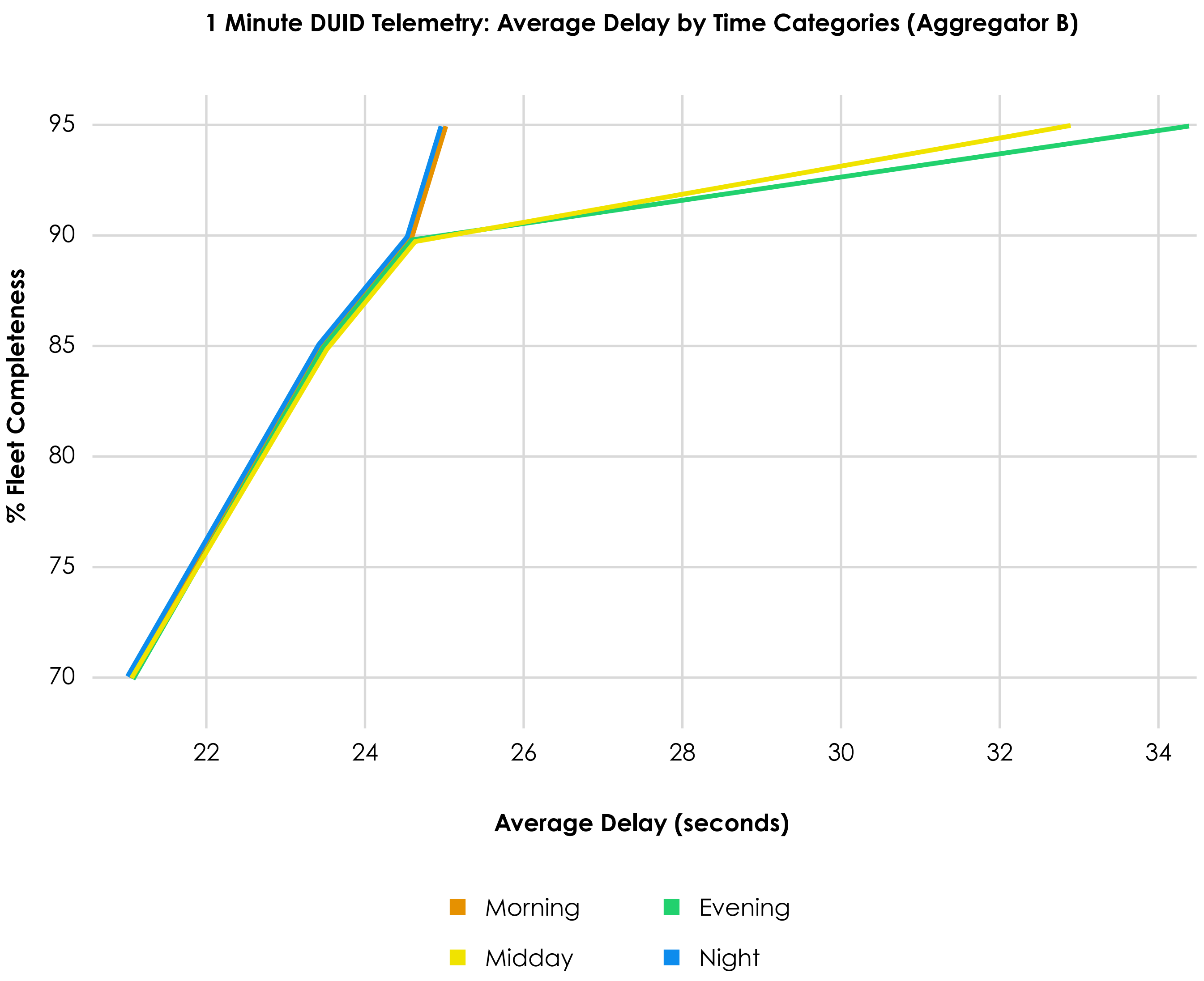


Figure 66 shows the results for Aggregator B. The average delay for Aggregator B to reach 95% data completeness for its fleet was between 25 and 34 seconds, depending on the time of day. Across the duration of the field trial, the average delay was 16 seconds, as shown in column 3 of Figure 64.

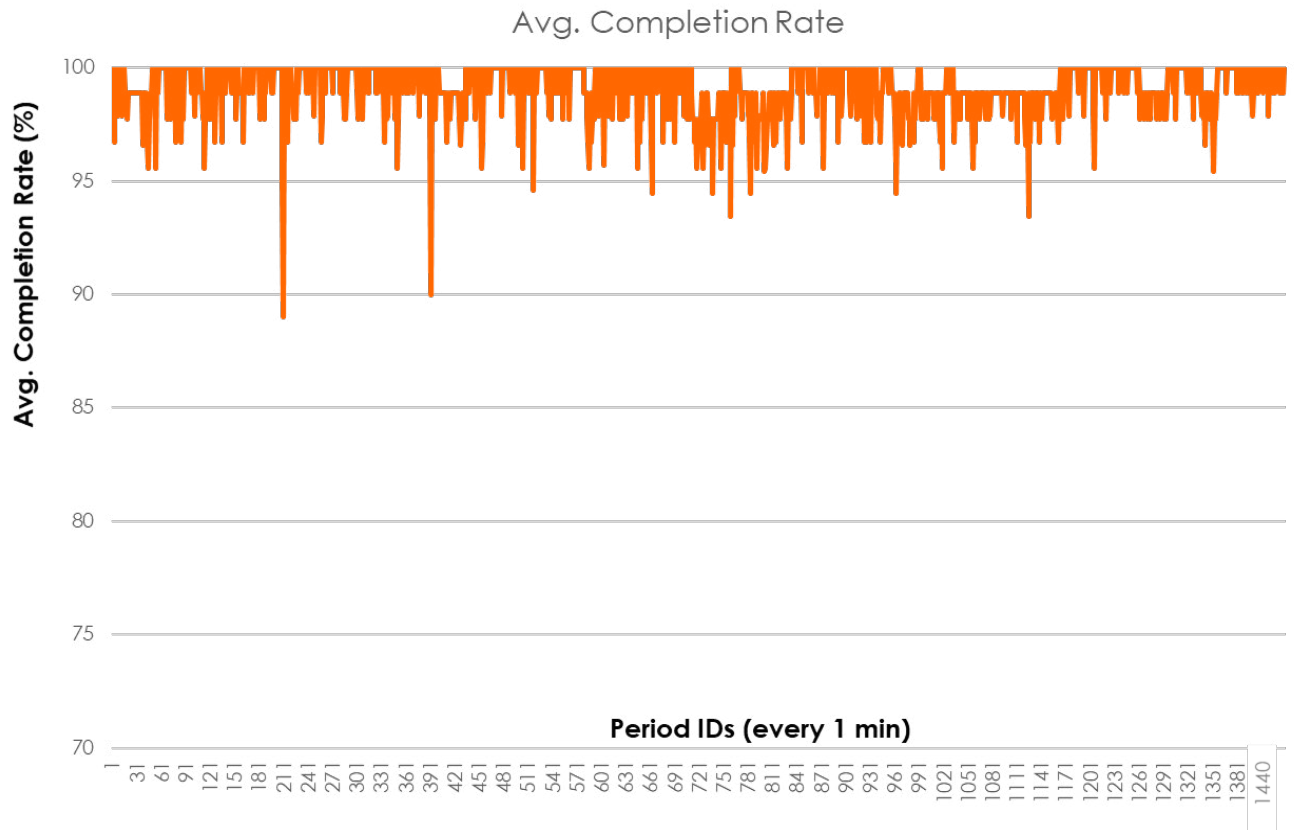
Midday (yellow line) and evening (green line) had the longest delays respectively. The average delay to reach 100% fleet completeness is not shown in the graph because the results are outliers. The average completion rate was 97% for 1 minute telemetry.

Figure 66 | Average delay (seconds) for Aggregator B to reach 100% fleet completeness



Aggregator C was unable to provide similar data with which to plot a distribution curve. Figure 67 shows the average data completion rate for Aggregator C. The average completion rate for each 1 minute interval was generally within 95%.

Figure 67 | Average completion rate for 1 minute resolution



Overall, the results indicated that as DUID level telemetry is transmitted more frequently, fleet coverage reduces due to latency between IoT devices and the aggregator's cloud.

This was more pronounced in some aggregators than others. Those with a more distributed system architecture seemed to enhance performance by storing the required site data locally and transmitting the data in a streamlined way, which mitigated some risk of momentary local communications failures contributing to lost and delayed data.

The three active aggregators also identified challenges to scaled DER communications with a higher data sampling rate. The key challenges and costs identified include:

- Increased IoT storage cost to account for internal communications outages (replacement of IoT devices to meet specification)
- Software upgrades – IoT vendor driven updates can have a large impact to fleet (5-10 minute outages were observed in Project EDGE)
- Energy management systems cost to upgrade legacy architecture (from pre-market participation)
- Increased cloud storage cost (doubling the data)
- Increased telecommunications cost (doubling the data)
- Synchronisation of time stamps to a 'source of truth' clock
- Parallel processing will likely be required, at a cost.

Overall, the aggregators noted that increased data sampling rates would lead to increased costs to serve their customers but had different opinions about how prohibitive this would be.

Aggregators noted that the technical communications capabilities required to facilitate market participation as scheduled resources can be developed. However, the communications to enable those technical capabilities were estimated to be expensive, although this could be more manageable through clever solution architecture design and economies of scale from a larger DER fleet.

One aggregator noted a contrast between different technology architecture models applied by aggregators, namely a distributed computing model focused on the home gateway against a centralised cloud-based processing architecture. Under a gateway model the management, processing, and transport of data may be more scalable, with modest cost impacts. A cloud computing model may face limitations and greater costs at large scale (i.e. millions of devices).

While the field trial has shown that transmission of portfolio telemetry at high frequency is technically possible, future data communications standards applying to DER need to be cognisant of both the power system risks that need to be managed and the commercial feasibility for aggregators to implement solutions that comply with the standards designed to manage these risks.

Another factor to consider is aggregator product architecture design.

Experience from the field trial and broader industry stakeholder engagement indicated that many aggregator software solutions seem to be constructed around a self-consumption only value proposition. as aggregators have not had much market experience (unless operating as a retailer) or wholesale market participation is not the first milestone on their product roadmaps (which is understandable given the current preference of most customers for optimising self-consumption, as discussed in Chapter 2).

Accordingly, new and existing aggregators may need to future-proof their technology roadmaps and build suitable technical communications capabilities for market participation over time.

INSIGHTS

Field trial findings on operational data exchange*

Feedback from aggregators participating in the Project EDGE field trial suggests that portfolio telemetry at 1 minute frequency and granularity could be possible.

While results from the field trial show that transmitting portfolio telemetry at 1 minute frequency was technically feasible within the constraints of the trial (e.g. smaller portfolio sizes), the associated operational costs, particularly when scaled, may be significant.

Aggregators would seek to recover those costs from the market or business-to-business service opportunities. Recovering these costs from customers appeared to have questionable commercial viability.

The field trial showed promising results that aggregators could develop the high-frequency telemetry capability needed to participate as scheduled resources in the wholesale market over time. However, to implement solutions they would need be financially feasible. A service-based stepping-stone approach would facilitate building market maturity to provide certainty of the return on investment (e.g. by unlocking revenue opportunities).

The proposed data exchange requirement of the Scheduled Lite mechanism appears to represent an approach that recognises the capabilities needed to integrate these type of resources (e.g. VPPs) in market processes. This rule change consultation process could be a vehicle to discuss some of the considerations identified through the Project EDGE field trial and discussed in this section.

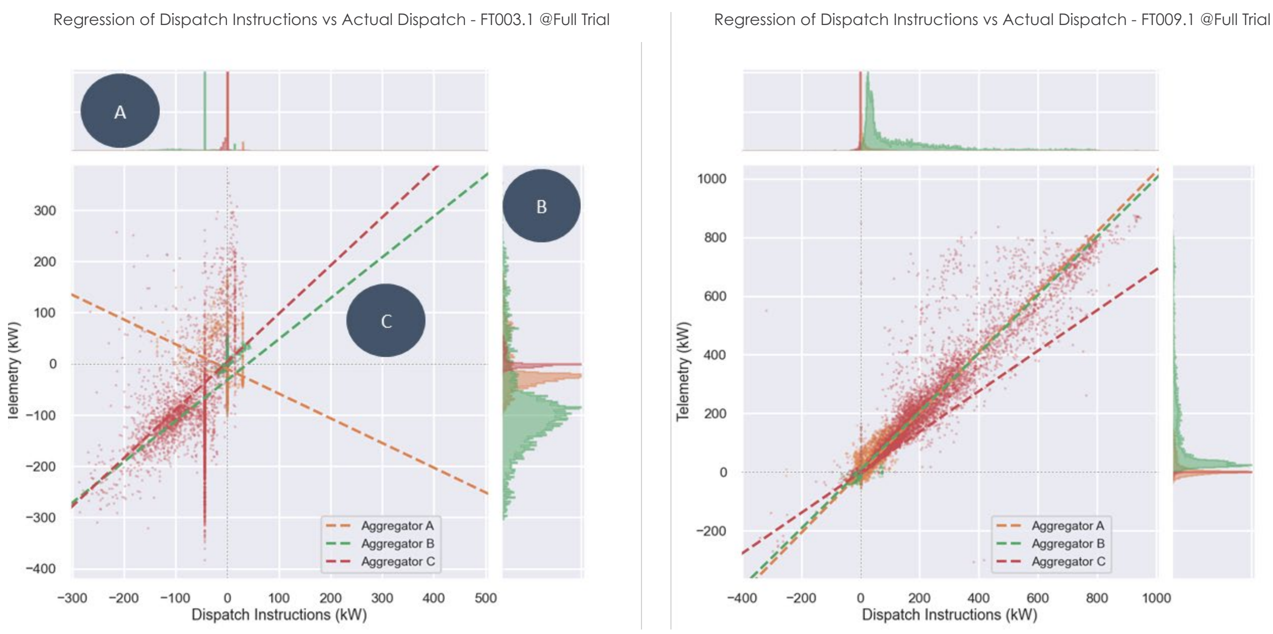
* Source: AEMO. 2023, Electricity Rule Change Proposal: Scheduled Lite, Appendix BL High Level Design, section 3.2.2, https://www.aemc.gov.au/sites/default/files/2023-01/ERC0352_Rule%20Change%20Request_Scheduled%20Lite%20-%20including%20Appendix.pdf

5.3.2.4 **Coordinating DER as a portfolio to meet dispatch target conformance**

Dispatch conformance improved over time for all three aggregators

A comparison of dispatch conformance from the first field test including all three aggregators (September 2022, the left graph of Figure 68) and the final field test (March 2023, the right graph of Figure 68), shows there was a clear improvement over time (7 months).

Figure 68 | Comparison of dispatch conformance across two time points for all aggregators



Note that Aggregator B (green) is challenging to visualise due to scale (it had a smaller fleet).

The top section (A) of the graphs in Figure 68 is a histogram of the dispatch instruction (kW) (the scale for this histogram is the scale of the x axis). This is the distribution of dispatch instructions in kW sent by AEMO.

For example, in the left graph, the red spike in the top section (A) shows that most dispatch instructions received by Aggregator C are close to 0kW (as shown by the spike aligning with, or close to, 0kW on the scale of the x axis).

In the right graph, the green histogram in the top section (A) shows that most of the dispatch instructions that Aggregator B received were to export between 0 to 100kW (the green peak is between 0kW and about 100kW on the scale of the x axis).

The right-hand section (B) shows the histogram (distribution) of the actual telemetry (kW) (the scale for this histogram is the scale of the y axis). Ideally, both histograms should be the same (i.e. A = B), indicating perfect dispatch target conformance.

In the left graph (the earlier field test), the actual telemetry (green shaded area) is spread widely in error (B versus A). Meanwhile, in the graph on the right (the last field test), the actual telemetry more closely follows the distribution of dispatch instructions (A ~ B). This indicates the aggregators initially had a larger range of error and over time their performance improved.

The middle section of both graphs (C) shows a scatter plot of dispatch instructions compared to telemetry for all intervals in the respective field tests. Ideally, the dot plots should fall on the line of best fit. When comparing the earlier field test (left graph) and the last field test (right graph), the points fall closer to the line of best fit in the last field test. This indicates an improvement in dispatch conformance over time between the two time points.

The line of best fit shows the trend between dispatch instructions and actual telemetry, and is used alongside the points to identify correlation between these variables. The closer the points are to their respective line of best fit, the stronger the correlation between the dispatch instructions and actual telemetry.

In Project EDGE as in the NEM, dispatch instructions were sent every 5 minutes. They generally reflected the aggregators' final bid, which was received no sooner than 5 minutes earlier (except for certain scenarios that tested performance with partial dispatch instructions, see section 5.3.2.8).

Overall, field tests results showed there were a few factors that led to dispatch conformance improving over time:

- **Forecasting model refinement:** As additional sites were added, dispatch conformance fluctuated as site specific historical data is needed to improve accuracy. As historical data accumulated and forecasting models were enhanced, accuracy and dispatch conformance improved.
- **Fleet capacity:** Results indicated that as aggregators' fleet capacity increased, their dispatch conformance improved. This was related to two factors. One was portfolio effect, where there were more sites in the aggregator's portfolio to coordinate in real time to achieve a target in the event some don't respond as anticipated. The second was improved forecasting accuracy, as increased portfolio capacity meant access to more data and customer sites.

Dispatch conformance comparison between Net NMI and Flex bidding

Field test data analysis indicated that Flex bidding resulted in lower maximum errors when aggregators' fleets were normalised by fleet capacity.

Figure 69 (all Net NMI bidding field tests) and Figure 70 (all Flex bidding field tests) compare dispatch conformance during field tests between Net NMI bidding and Flex bidding over time (between May 2022 and April 2023) across all three active aggregators. The figures show how the aggregators' telemetry (orange) performed against the dispatch instructions (blue). The green shows the normalised absolute error (a value closer to 0 is ideal).

Figure 69 | Dispatch conformance for all aggregators during Net NMI bidding field tests

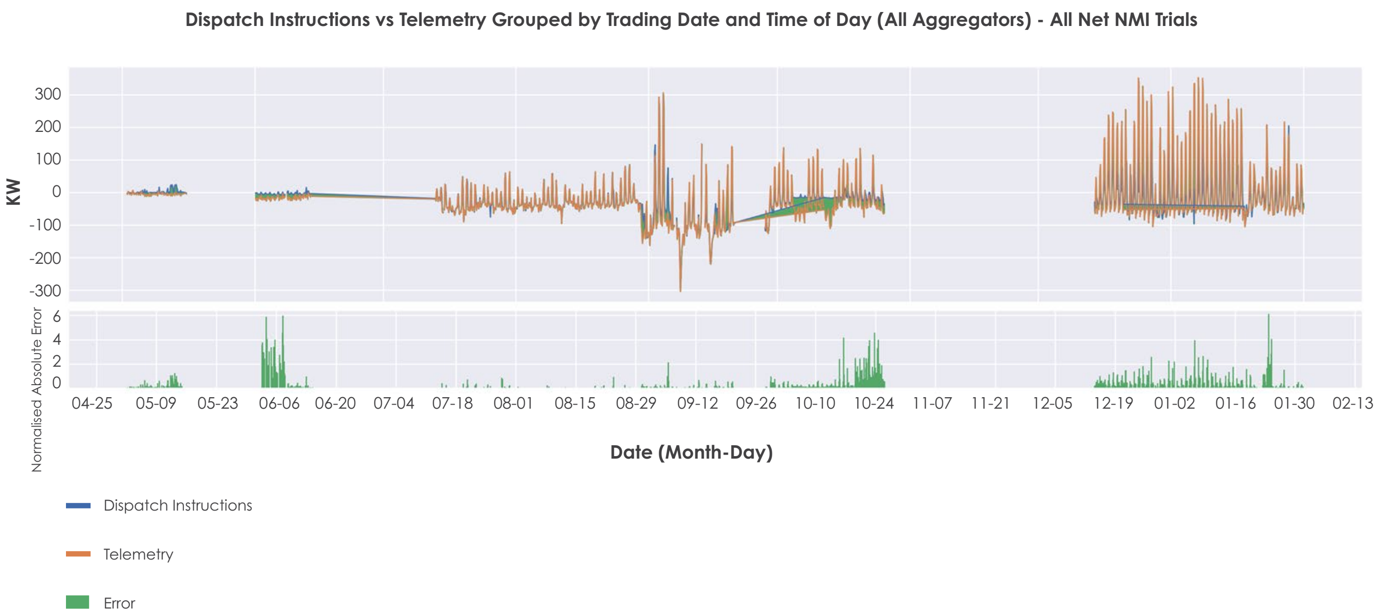
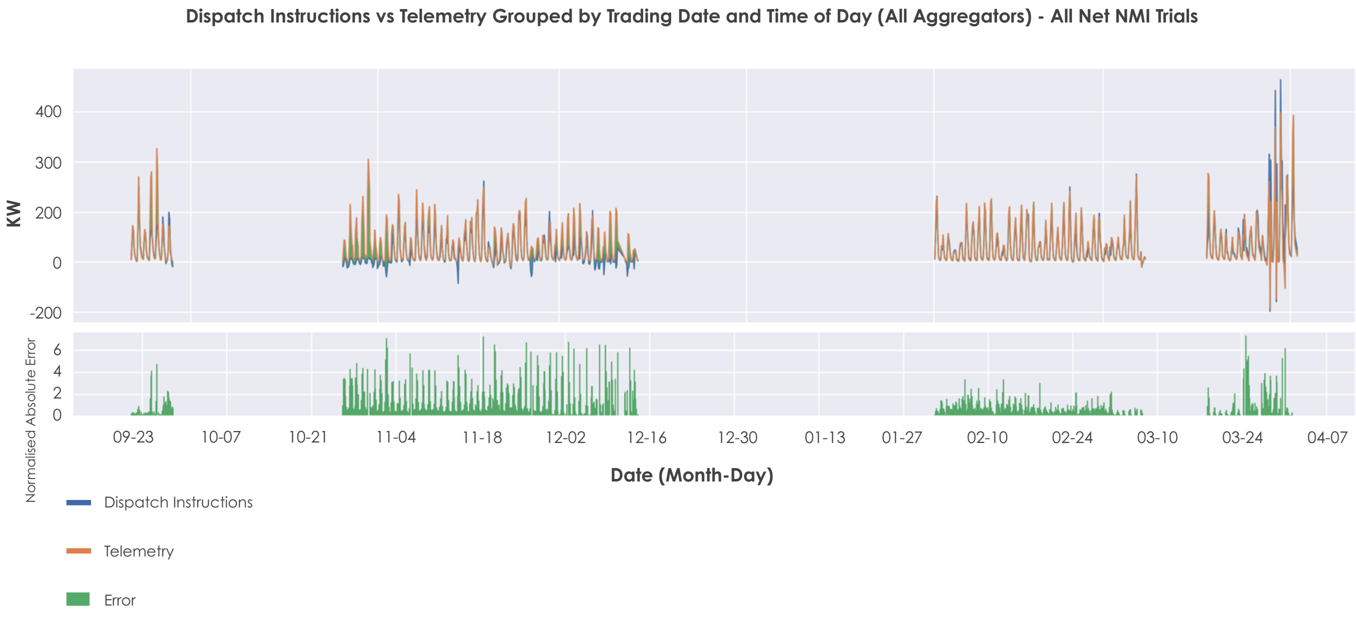


Figure 70 | Dispatch conformance for all aggregators during Flex bidding field tests



Comparing the two figures shows the normalised absolute error values (green) ranging from 0 to 6 with Net NMI bidding over time across the field tests. Meanwhile, there is a decrease in error with Flex bidding over time (green and normalised absolute error values ranging from 0 to 0.6).

These field test results show that dispatch conformance errors were higher with Net NMI bidding compared with Flex bidding by a factor of 10.

In addition to varying available controllable load and generation capacity through communications outages or customer preferences, errors are driven by changes in uncontrolled load (customers' essential electricity service), which is included in the Net NMI bid.

Removing the uncontrolled load under Flex bidding can enable aggregators to better manage risk of dispatch non-conformance as this would be evaluated against the controlled power only. This is particularly evident when being dispatched for a step change response (see discussion around Figure 83 in section 5.3.2.8).

However, Flex bidding does not necessarily mean that aggregators can ignore uncontrolled load. When operating self-consumption objectives, aggregator bids for flexible resources will still be responsive to impacts on available capacity from their customers' uncontrolled resources (not individual sites), as seen in Figure 81 in section 5.3.2.8.

INSIGHTS

Field trial findings on dispatch conformance under different bidding quantity definitions

Trends in data from Project EDGE field tests suggest that absolute dispatch conformance error will scale to a higher degree with Net NMI bidding, rather than Flex bidding, as VPPs grow.

While the results indicate overarching benefits to system security and market efficiency from Flex bidding compared to Net NMI bidding, it is important to note both bidding quantities will have challenges for aggregators developing forecast and dispatch capabilities to deliver energy services beyond pure solar self-consumption.

Engagement with aggregator stakeholders identified that initial system designs that cater to a 'prioritise self-consumption' business model are often centred around optimising the use of customer generated rooftop PV by monitoring at or close to the site's meter and reacting to fluctuations in uncontrolled load using a battery or other assets via logic distributed at each site. From this perspective, Flex bidding does not create material efficiencies for an aggregator.

Power system security and market efficiency benefits would be limited, if not undermined, if large DER portfolios participated in this way with largely reactive (short notice) step change responses (discussed in section 5.3.2.8).

Graduating beyond this initial 'individual site management' approach to providing genuine 'aggregation' services where DER are operated as a portfolio across many sites would require identifying the available capacity that can be dispatched ahead of time.

Regardless of the bidding definition, aggregators would need capability to forecast solar generation, battery state of charge and uncontrolled load. For example, if a customer's battery is being used to power the uncontrolled loads in the evening, the aggregator would need to understand those loads.

INSIGHTS

Field trial findings on dispatch conformance under Flex bidding

Evidence suggests that dispatch conformance is more accurate under Flex bidding than under Net NMI bidding.

It is important to note that:

- Flex bidding still requires aggregators to respond to changes in uncontrolled resources when operating self-consumption objectives.
- Flex bidding is agnostic to DOE definitions. Aggregators can participate in the wholesale market under Flex bidding while managing conformance to either Net NMI DOEs or Flex DOEs.

Desktop analysis of Flex bidding impacts on wholesale market settlement

Flex bidding, as tested by Project EDGE, would enable customers to have their controllable resources recognised in wholesale settlement, independent of their passive resources. This arrangement would be enabled within existing market frameworks (including mechanisms for settlement, metering, financial responsibility and market participation), but only via establishment of a second connection point to the distribution network.[205]

A desktop analysis was conducted to obtain insights on how the bidding quantity definition affected wholesale market settlement outcomes. Project EDGE was an off-market trial, with separate field tests for both Net NMI bidding and Flex bidding.

Wholesale market settlement outcomes were calculated in the desktop analysis using aggregated portfolio telemetry data from all field tests. This telemetry data included both Net NMI and Flex quantities for every 5-minute dispatch interval of the field trial. This meant the aggregators' operational behaviour was observed in both Net NMI and Flex quantity definitions, whether the fleet was primarily self-consuming or being coordinated to achieve a step change in load or generation in response to a given high or negative price event.

205 AEMC. N.d., Integrating energy storage systems into the NEM. https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

It is important to note that the desktop analysis included only wholesale electricity market settlement for an aggregator (i.e. it excludes network charges and end-customer bills). It treats the aggregator as either:

- The FRMP for the whole site, under Net NMI. That is, the aggregator is responsible for everything in wholesale market settlement, including uncontrolled and controllable elements, and is treated as if it is the retailer at the site
- The FRMP only for the collective flexible resources controlled by the aggregator, under Flex. It is assumed there is a separate retailer, who is treated as the FRMP responsible only for the uncontrolled load/generation.

The simulated scenarios did not consider customer outcomes, which would depend upon a variety of factors, including the contractual agreements with the aggregator, the revenue earned by the aggregator in the market and the retail tariff under the aggregator's contract with the FRMP.

Network charges were also not factored into the wholesale settlement desktop analysis. Network charges would apply based on demand, controlled load tariffs and consumption, based on the net withdrawal (and potentially also net injection) to the network.

Table 9: Desktop analysis on wholesale settlement arrangements under Net NMI and Flex approaches

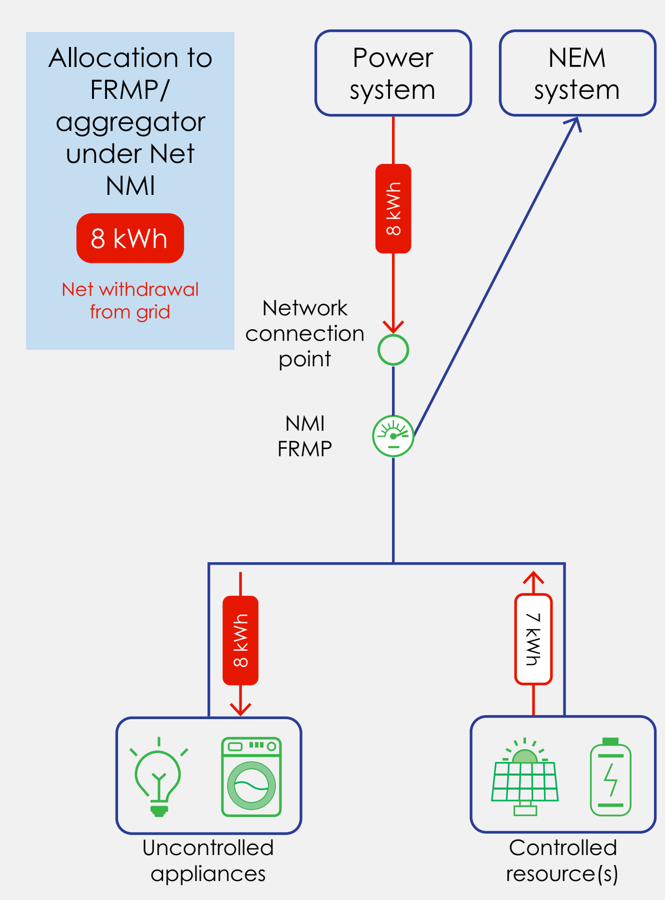
	Net NMI	Flex
Simulated financial responsibility in market settlement	Aggregator treated as FRMP (i.e. retailer) for whole site (all customer load and DER behind connection point, both passive and controlled) for the entire portfolio	Aggregator treated as FRMP for flexible resources under the aggregator's control only (across all sites in the portfolio) There is a separate retailer who is treated as a separate FRMP responsible for uncontrolled resources
Network charges	Not part of the simulation Only applied to net withdrawals (and potentially injections) from the grid	
Data used for simulated settlement	Aggregated portfolio telemetry data for whole site	Aggregated portfolio telemetry data of the controllable assets only

How settlement was calculated under Net NMI and Flex arrangements (off-market, desktop analysis)

Under Net NMI, the aggregator (which is treated as the FRMP for the whole connection point) is paid at the wholesale spot price for net injections to the grid, and pays the wholesale spot price for net withdrawals from the grid. This is illustrated in Table 10 for net withdrawal (left hand side) and net injection (right hand side) scenarios.

Table 10 | Examples of simulated settlement energy allocation calculations for Net NMI

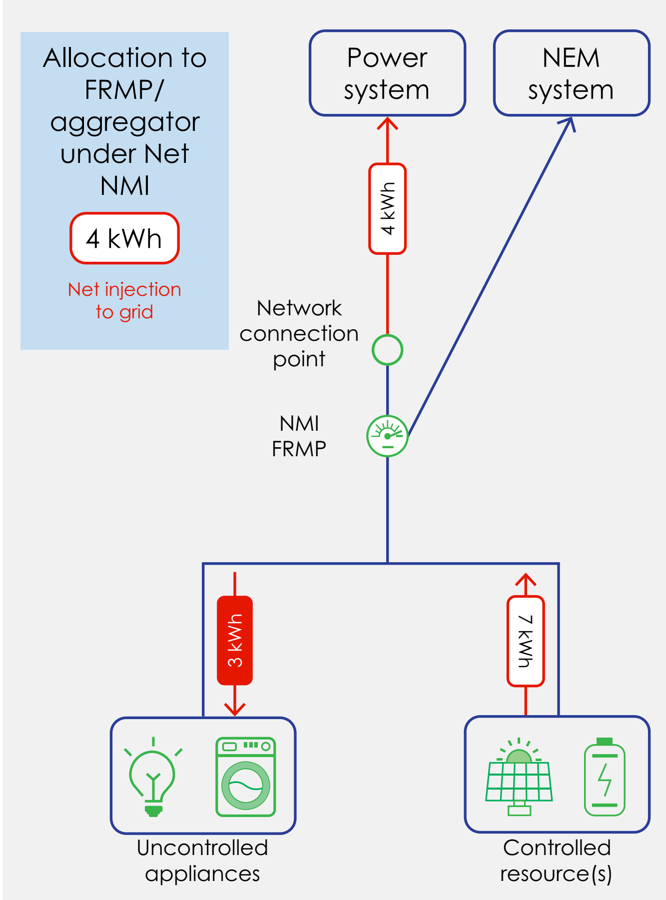
Net NMI – net withdrawal



In this Net NMI example:

- The customer's uncontrolled appliances are consuming more than the controlled resources are generating.
- The aggregator is treated as FRMP for the whole site in the desktop analysis.
- The net withdrawal from the grid (8kWh) is allocated to the aggregator in wholesale settlement.

Net NMI – net injection



In this Net NMI example:

- The customer's uncontrolled resources are consuming less than the controlled resources are generating.
- The aggregator is treated as FRMP for the whole site in the desktop analysis.
- The net injection to the grid (4kWh) is allocated to the aggregator in wholesale settlement.

Under Flex, a subtractive wholesale settlement arrangement was used to allocate energy between the retailer (which, for the purpose of this analysis, is treated as the FRMP for the uncontrolled resources) and the aggregator (which is treated as the FRMP for the controlled resources).[206]

The subtractive settlement arrangement enables each FRMP to be allocated the flows of energy for which it is responsible in wholesale settlement. This is similar to the subtractive settlement arrangement illustrated in the 'unlocking CER benefits through flexible trading' rule change proposal [207] and uses mechanisms for settlement similar to those within embedded networks in the NEM.[208]

This is illustrated in Table 11 for net withdrawal (left hand side) and net injection (right hand side).

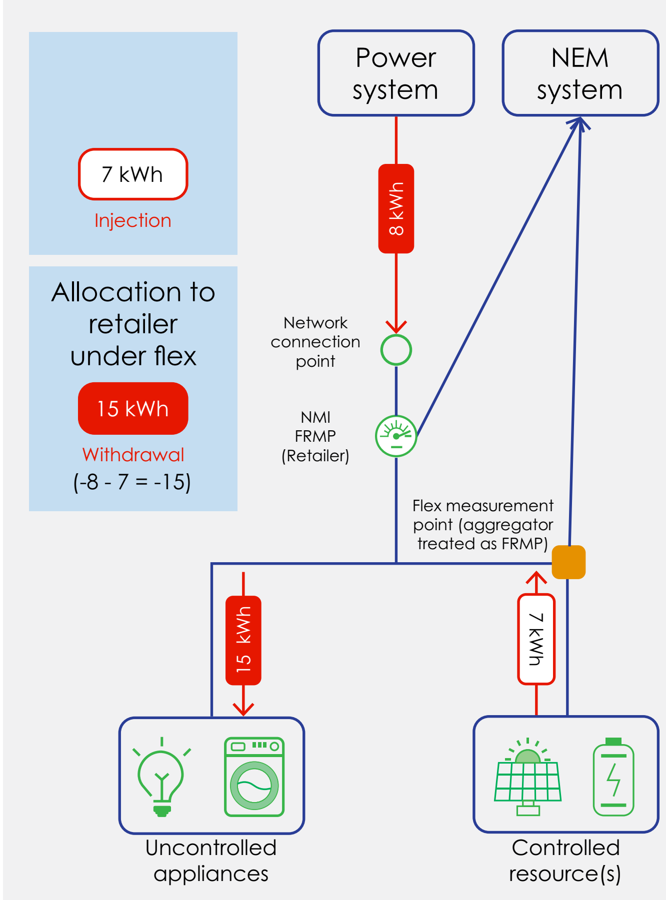
206 In the market, this would require the aggregator's to have settlement quality metering.

207 AEMC. N.d., Unlocking CER benefits through flexible trading. https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

208 AEMC. N.d., Embedded networks. https://www.aemc.gov.au/rule-changes/embedded-networks

Table 11 | Examples of siimulated settlement energy allocation calculations for Flex

Flex – net withdrawal



In this Flex example:

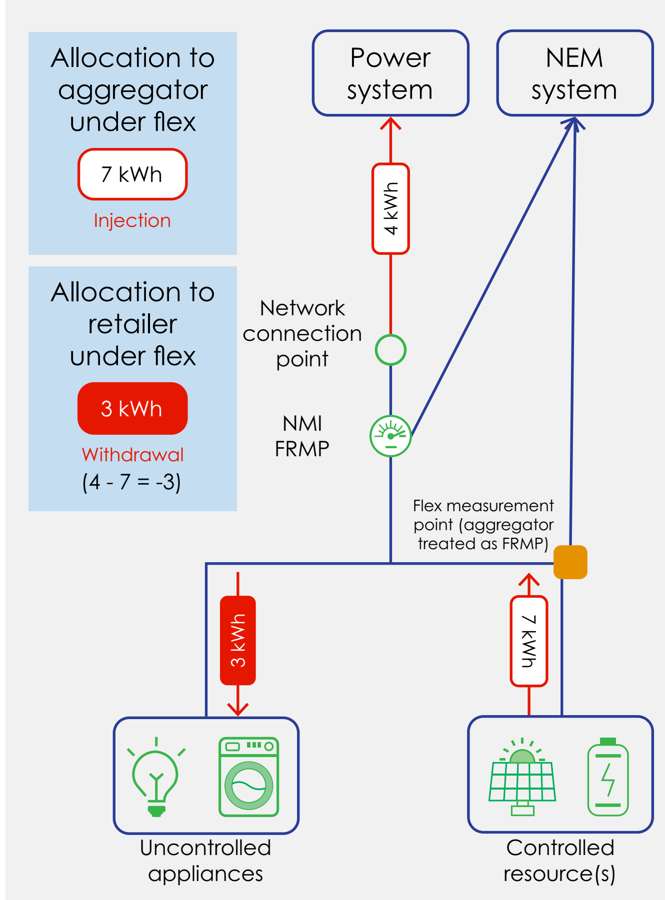
- The customer's uncontrolled appliances are consuming more than the coordinated DER resources are generating.
- The aggregator is treated as FRMP for the controlled resources only; the retailer is FRMP for the uncontrolled portion.

The wholesale settlement allocations are as follows:

The 7kWh generated by the controlled resources is allocated to the aggregator.

The 15kWh consumed by the uncontrolled appliances is allocated to the retailer (although the 7kWh from the controlled resource generation is being consumed by the uncontrolled appliances, the retailer is still responsible for purchasing the 7kWh in wholesale energy settlement but may not attract network charges).

Flex – net injection



In this Flex example:

- The customer's uncontrolled appliances are consuming less than the coordinated DER resources are generating,
- The aggregator is treated as FRMP for the controlled resources only; the retailer is FRMP for the uncontrolled portion

The wholesale settlement allocations are as follows:

The 7kWh generated by the controlled resources is allocated to the aggregator.

The 3kWh consumed by the uncontrolled appliances is allocated to the retailer (although the 3kWh from the controlled resource generation is being consumed by the uncontrolled appliances, the retailer is still responsible for purchasing the 3kWh in wholesale energy settlement but may not attract network charges).

The Flex model presents an opportunity for aggregators and their customers to maximise the value of their assets, while potentially avoiding incurring additional network charges, as the flow of energy at the network is unaffected – as demonstrated in the examples above.

All else being equal, the settlement arrangement applied to Flex, which recognises flexible resources independently in wholesale settlement, results in a transfer of value from the retailer to the aggregator. It enables the aggregator to inject and be paid for the gross generation in the market and access greater revenue opportunities to share with the customer.

Currently, in the absence of a more accessible model in the market to enable aggregators to become financially responsible for a customer's flexible resources, aggregators must strike a hedging agreement with retailers to benefit from wholesale market exposure.

Desktop analysis of wholesale settlement results

This analysis was undertaken with the objective to assess whether there is value in separating controlled resources from uncontrolled loads for the purposes of market participation.

The desktop analysis used wholesale market settlement outcomes for aggregators only, based on field trial data. Results for each aggregator are shown in Figures 71, 72 and 73.

The figures show price brackets on the x axis, where $0 - $300 is the price band during 'benign market conditions'. The right hand side bars of each figure show the total wholesale market revenue (positive gain and negative loss) under each bidding quantity definition (blue for Net NMI participation and green for Flex participation). The y axis shows the value of revenue or loss.

Figure 71 | Simulated wholesale market settlement results for Aggregator A

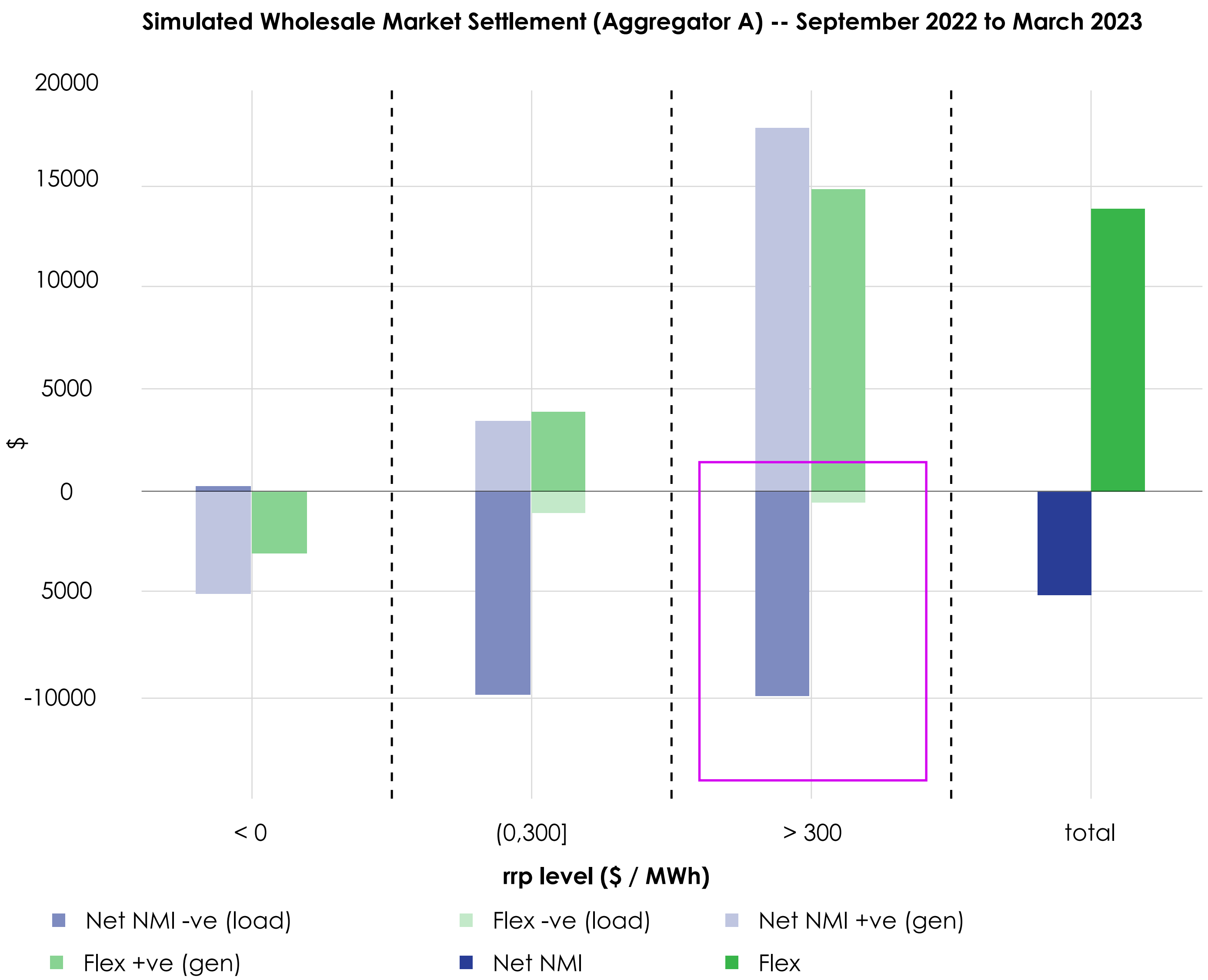


Figure 72 | Simulated wholesale market settlement results for Aggregator B

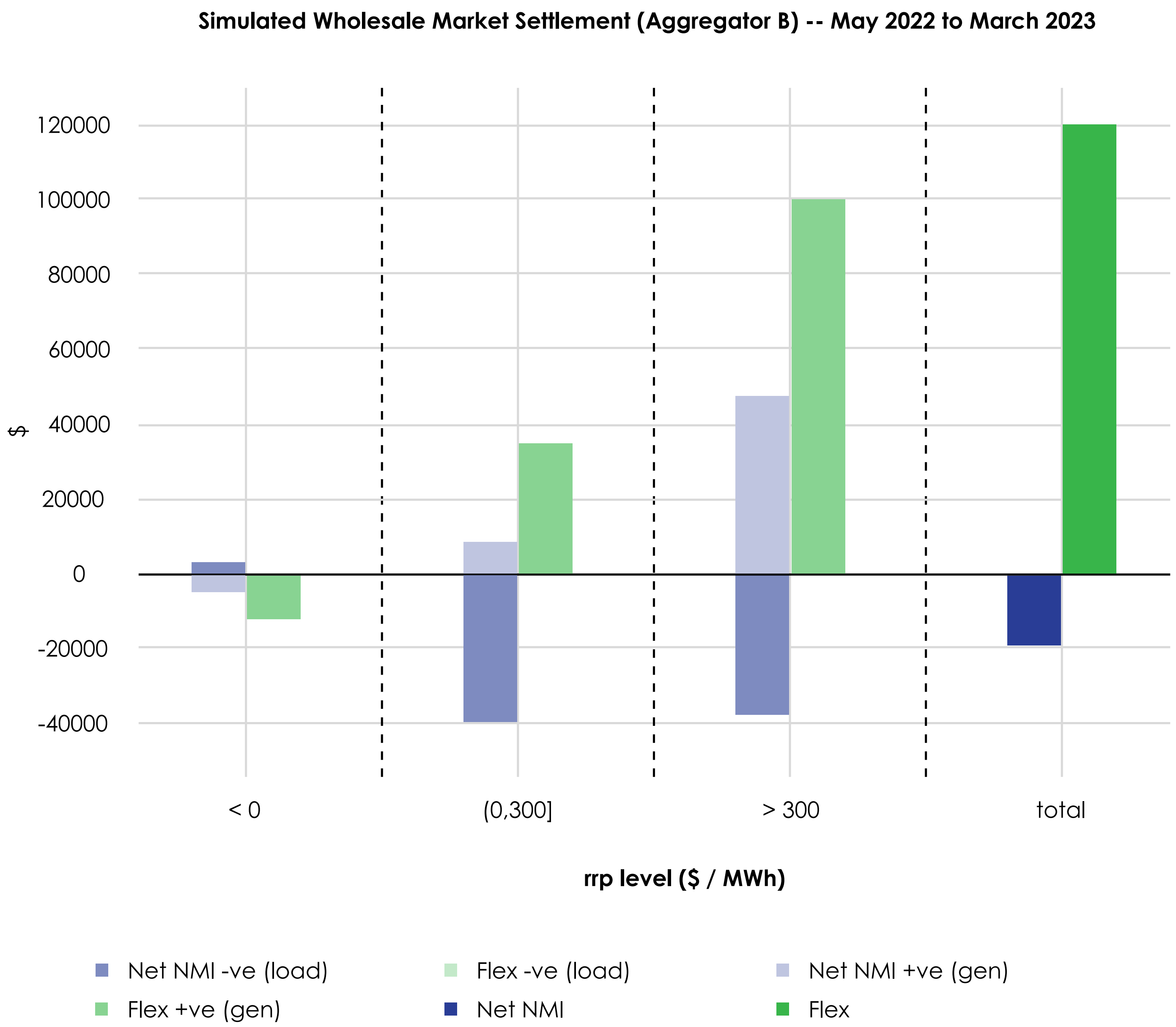
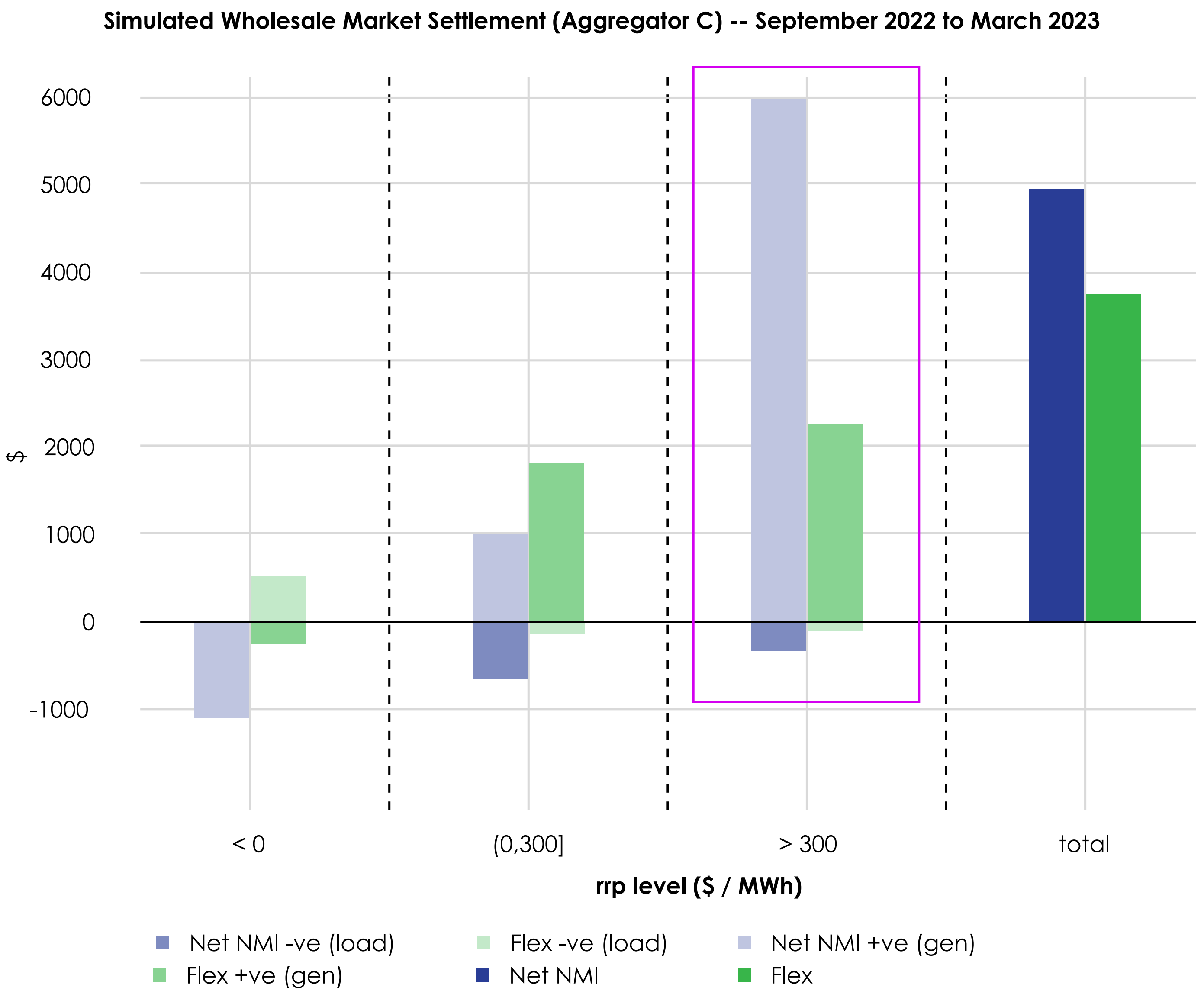


Figure 73 | Simulated wholesale market settlement for Aggregator C



Bars that fall below the black line ($0) for positive wholesale market prices indicate that an aggregator's customers were consuming more than they were generating (or had fully stored it in batteries). Therefore, they had to withdraw energy from the grid when the wholesale price was positive, losing money. One example of this scenario is highlighted through the purple rectangle in Figure 71.

If the dark blue bar (Net NMI load) is greater than the lightest green bar (Flex load), as is the case across all aggregators, this represents a greater loss under Net NMI bidding associated with the inability to hedge the influence of uncontrollable load being demanded.

Overall, the results showed:

- **During negative price events** (far left of each figure, < $0) two of three aggregators made more revenue under Flex bidding compared with Net NMI bidding. Aggregator B did not, as it constrained its export to zero during negative prices; however, because solar was still generating to meet loads, the aggregator was being charged to generate the solar that was 'self-consumed' (see explanation of settlement calculations above).
- **In BAU ($0 - $300),** all aggregators made more revenue under Flex bidding compared with Net NMI bidding. There is an avoided risk of price exposure under Flex bidding because the aggregator can make its portfolio equal zero (as observed in Figure 83 in section 5.3.2.8). Meanwhile, under Net NMI bidding, the aggregator would need to withhold (or be more conservative with) its capacity to ensure it is managing customers' uncontrolled load requirements (discussed in section 5.3.2.2). This may reduce the volume of portfolio capacity that an aggregator can monetise in the wholesale market.
- **Where the price is above $300,** two aggregators made more money in Flex bidding compared with Net NMI bidding. It appears Aggregator C made more money under Net NMI bidding (purple rectangle).

However, this result incorporates an error (for the data provided for this analysis only) whereby controlled PV generation has not been reflected in the Flex settlement results due to a miscalculation in controlled generation (confirmed by Aggregator C).

Controlled generation should be composed of both PV and battery generation; however, only the battery generation was reported. It is likely the aggregator would in fact make more revenue in Flex than what is represented by the dark brown bars in Figure 73, which would be consistent with the other aggregators.

This analysis shows that significantly more wholesale value is available for aggregators from separating controlled resources from uncontrolled loads for the purposes of market participation.

Considerations of how aggregators would take and then ultimately share value with customers would involve having to offset customer payments to the retailer for uncontrolled load and network charges if an aggregator's controllable assets were not available for self-consumption.

Another consideration for aggregators devising a product strategy is that in the majority of instances wholesale prices are low but positive. In Flex participation, aggregators would be paid for the flex controllable generation bid to cover their customers' uncontrolled load in a self-consumption arrangement, compared with a net NMI arrangement where their exports would be 0 and therefore earn no revenue.

It would be up to an aggregator to take a broader year-long view, considering the potential variability of market prices, to develop offers to customers that passed a customer's 'better off overall' test.

The 'unlocking CER benefits through flexible trading' rule change proposes to enable unbundling of flexible resources in wholesale settlement

AEMO's 'unlocking CER benefits through flexible trading' rule change proposal would provide an enduring, in-market mechanism for customers and their providers to independently manage flexible energy resources in wholesale settlement (as an alternative to establishing a second connection point to the network).

The proposal allows customers to establish a secondary connection point (or 'private metering arrangement') for controllable resource(s) within their electrical installation. It enables customers to access more competitive offers and services for their controllable resources, independent from their general electricity supply, enhancing their ability to be rewarded for their flexibility.

Similar to what was trialled in Project EDGE, the rule change as proposed by AEMO, would also allow an aggregator to balance self-consumption models with price-responsiveness.

AEMO's rule change proposal provides an extensive overview of all aspects of the design and operation of Flexible Trader Model 2 (FTM2).[209]

209 AEMO. 2022. Electricity Rule Change Proposal: Flexible trading arrangements and metering of minor energy flows in the NEM. https://www.aemc.gov.au/sites/default/files/2022-05/ERC0346%20Rule%20change%20request%20pending.pdf

5.3.2.5 Linear ramping

Ramping and the requirement for a linear trajectory is critical for system security and will be a key capability challenge for aggregators

The rate of change of output of generation (the ramp rate) is a key factor that leads to disruptions in power system frequency. Material disruptions to system frequency reduce power system security.

As the capacity of coordinated DER portfolios scales, it will create risks that a rapid change in a portfolio's output to meet a dispatch instruction will lead to system frequency perturbations that compromise system security

The NER requires AEMO, as part of dispatch instruction, to specify a ramp rate or a specific target time for a generating unit or a wholesale demand response unit to reach the dispatch target.[210]

In the absence of a ramp rate provided directly in the dispatch instruction, the AEMO dispatch operating procedure prescribes that certain units must linearly ramp their active power across the trading interval in a uniform way, from their active power at the time of receiving the dispatch instruction to the dispatch target at the end of the trading interval, subject to certain conditions.[211]

Failure to meet linear ramping obligations in dispatch conformance would also impact VPP causer pays costs, as those deviations would cause an increased need for regulation of FCAS.[212]

All aggregators found it challenging to conform to linear ramping between dispatch targets but two developed capabilities within a short timeframe

During field tests, one of the aggregators did not actively seek to develop linear ramping capabilities or meet linear ramping requirements. The other aggregators implemented linear ramping capabilities toward the end of the trial within a few months of development, which demonstrates it is feasible.

All aggregators prioritised working on functionality for DOE and dispatch conformance, and building systems for forecasting capabilities prior to building systems for linear ramping capabilities.

All aggregators noted linear ramping was challenging due to the nature of DER. Unlike large-scale resources (often single units) that can be ramped up through centralised control, DER requires the coordination of multiple, small, distributed devices that vary in capacity and communications availability. This variability would need to be coordinated via small power adjustments across the portfolio (not necessarily in a uniform manner at each individual site level) to maintain an overall linear trajectory.

The aggregator that did not seek to develop ramping capabilities was opposed to the concept of coordinating customer assets to achieve linear ramping at each interval because it considered there was no financial value incentive for the customer.

This aggregator was of the view that customers do not want their devices controlled for the sole purpose of meeting dispatch targets or requirements if there is no economic value in doing so.

As noted in Chapter 2 regaring Deakin's findings from its consumer research, customers are open to additional export if they are provided assurances that they will be better off overall. Additionally, Deakin's research found customers preferred automated control of their DER devices (i.e. they do not need to know how their DER is being used at all times) if they trust they will be better of overall and have access to information about the VPP activity in case they desire to track it.

210 AEMO. 2023, Dispatch Procedure, p 21, section 2.8. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705%20Dispatch.pdf. Section 3 of the Dispatch operating procedure outlines the approach and process for non-conformance with dispatch targets.

211 AEMO. 2023, Dispatch Procedure, p 21, section 2.8. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705%20Dispatch.pdf

212 The recovery of payments for regulation services is based on the 'causer pays' methodology. Under this methodology, the response of measured generation and loads to frequency deviations is monitored and used to determine a series of causer pays factors.

AEMO. 2023, Regulation FCAS Contribution Factor Procedure: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/regulation-fcas-contribution-factors-procedure-final.pdf?la=en Determination of Contribution Factors for Regulation FCAS Cost Recovery. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/regulation-fcas-contribution-factors-procedure-final.pdf?la=en

The view of another aggregator participating in Project EDGE is that it is technically possible to have quite good ramp rates and fleet power targets executed in VPPs (see the following discussion in this section on field test results for linear ramping).

However, it would be dependent on the entire technology stack and overall architecture, the capabilities of each layer and the constraints and performance of the interfaces between each layer. There would be associated costs to build and use each layer.

Considerations for aggregators seeking to develop ramping capabilities include:

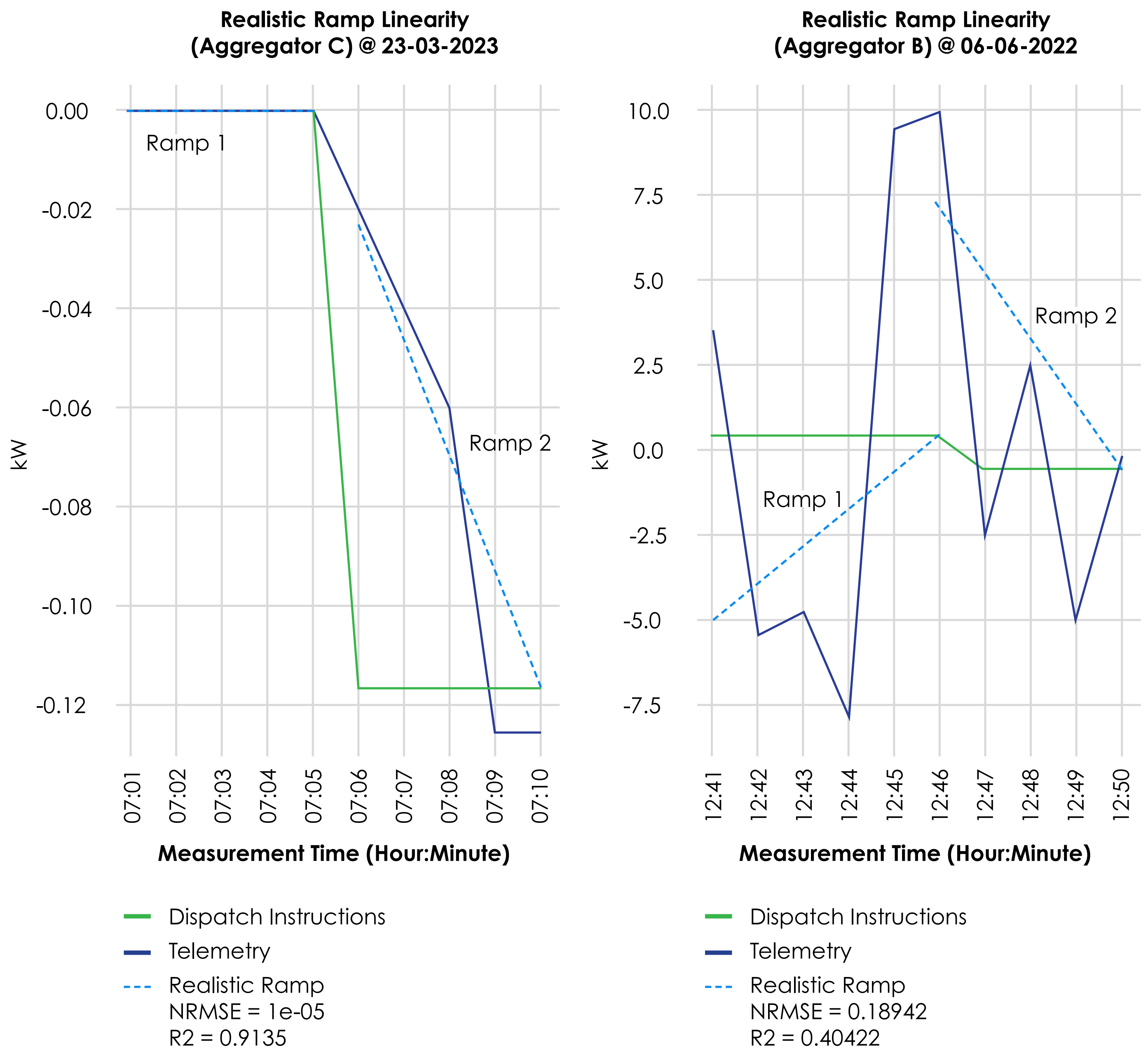
- Aggregators would need to implement step changes in their algorithms, separating devices into various channels so that they come online at different times. This would result in a more linear trajectory.
- Some devices may have default settings that would enable the aggregator to linear ramp from one site to another rather than having large step changes. These settings could allow the aggregator to set the curve at which they start and to which they ramp.
- Aggregators could progressively develop capabilities to separate their portfolio so that it is not controlled as one block. Rather, the aggregator could control the cycle at which sites are activated and when.
- Aggregators could segment the dispatch target in such a way over the entire fleet that achieves a curve across various blocks.

Figure 74 highlights the difference between better conforming and non-conforming linear ramping performance.

While the project completed limited testing, and time constraints resulted in limited development of the required capabilities by aggregators, the results overall indicate that it is feasible for aggregators to develop linear ramping capabilities.

The figure compares the performance, during field tests, of linear ramping by one of the aggregators that developed linear ramping capabilities and sought to actively linear ramp (left graph), with the performance of the aggregator who did not develop linear ramping capabilities (right).

Figure 74 | Comparison of better conformance with linear ramping and performance not actively attempting to linear ramp



Note:

The green line reflecting the dispatch instruction is not a straight line from the 5 minute to the 5 minute (e.g. on the left graph, a straight line from 07.05 to 07.10). This is because dispatch instructions are reflected at the minute end. This means the dispatch instruction at 07.05 and 1 second will be the same as at 07.10. But because the graph measures at the minute mark, it shows the dispatch instruction for a given interval at the plus 1 minute point of the 5-miute interval (e.g. 07.06 in this example).

The blue dashed line for ramp 1 on the right graph is shown to begin at -0.5kW rather than 3.5kW. This is because it is calculated on the 12.40 value, which is not visible on the graph. This is why it has a positive ramp from -0.5kW rather than a negative ramp from ~3.5kW. For the same reason described above for the dispatch instruction, the ramp is shown to begin at the plus 1 minute point of the 5-minute interval.

These graphs show ramping results for an aggregator's whole portfolio, and the dispatch instruction was based on the aggregator's final bi-directional offer during benign market conditions. The example of better conformance occurred during Flex bidding, while the poor conformance occurred during Net NMI. This comparison is not intended to compare linear ramping under the different bidding quantities. Rather, it is intended to illustrate what better conformance looks like compared to poor conformance, and to highlight there is promise in aggregators developing linear ramping capabilities, considering they had limited time to develop these capabilities but some managed to achieve conformance nonetheless.

It should be noted that the results are based on analysis of linear ramping overall.

The graph shows the dispatch instruction (green line), the telemetry (blue line) and the R^2 (blue dashed line). The R^2 value reflects how well correlated actual dispatch conformance is to a realistic ramp (measured from where the aggregator ended dispatch for the previous interval and therefore the point from which it will need to ramp from to meet the next target). An R^2 value of 1 would suggest a perfect linear correlation. The left graph shows the aggregator achieved an R^2 value close to 1 for both of the 5-minute dispatch intervals.

The telemetry, measured from where the aggregator ended dispatch at the end of the interval, follows a relatively linear ramp toward the following dispatch target – the telemetry (blue), closely aligns with the expected realistic ramp (the dashed blue line).

The right-hand graph shows that the telemetry, using the same analysis method, does not follow a linear ramp toward the following dispatch targets – the telemetry (blue), does not align with the expected realistic ramp (the dashed blue line).

At scale, a rapid rate of change could create system security issues. At the scale tested within the Project EDGE field trial, poor linear ramping performance may not pose a significant risk to system security. However, in a high DER future with multiple aggregators and large capacity portfolios, including C&I customers, it will be important that aggregators can meet linear ramping requirements.

Aggregators may find it more challenging to linear ramp when generating compared to loading, and based on DER type.

For example, aggregators found it was simpler to linearly ramp discharging (generating) batteries to meet a target than linearly ramping rooftop PV generation. Rooftop PV can be affected by clouds and instantly react in a non-linear way.

Accordingly, there may be levels of complexity for which aggregators will need to build up maturity. Fleet size could also improve this capability (see section 5.3.2.1) by providing additional opportunity to smooth variability from distributed resources and additional controllable capacity as part of the aggregation.

INSIGHTS

Field trial findings on linear ramping

Overall, the results demonstrate linear ramping will be a key capability challenge aggregators will need to overcome to participate in the dispatch process with portfolios of material capacity.

In Project EDGE two of the three active aggregators managed to build some linear ramping capability within a few months. This highlights capability can be developed progressively and supports the need for a stepping-stone approach to aggregator participation as scheduled resources that includes operating DER as a portfolio.

5.3.2.6 DOE conformance

Aggregators will need to improve DOE conformance to participate in a wide-scale rollout of DOEs

In Project EDGE, DOE conformance was examined in two ways:

- DNSP-led monitoring of NMI-level DOE conformance, ex-post using smart meter data
- AEMO considered DUID-level DOEs (the sum of all NMI DOEs in a VPP portfolio) as a coarse check against the DER aggregator bid quantity to ensure an aggregator was not dispatched outside of the total network limits assigned to them by the DNSP.

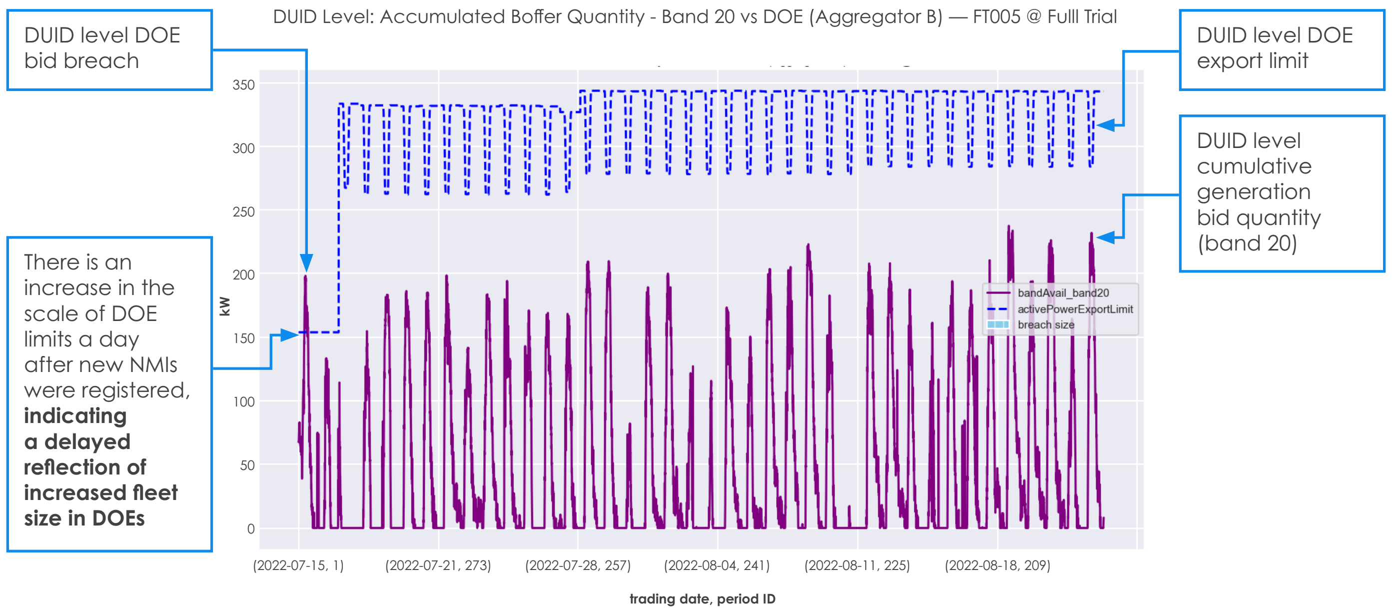
For the purpose of the results discussed in this section, a breach was defined to mean performance that did not exactly match the DOE allocated to a particular site. This means that performance 0.1kW outside of the DOE limit resulted in a breach.

This may not be how industry chooses to define a DOE breach, and the use of a strict definition of a breach in the field test results analysis does not indicate industry should define a DOE breach in the same manner. The consequences of DOE breaches are discussed in section 4.3.5.2 Table 3.

Field tests demonstrated aggregators generally conformed to DOEs, both at the portfolio level (DUID) and NMI level.

Although rare, DUID level DOE breaches were observed in the field tests. Figure 75 shows an example of a DOE bidding breach.

Figure 75 | Example of DUID DOE breach during field tests



The cause of these occurrences was the absence of an established method to synchronise new NMI enrolment in an aggregator portfolio with DOE updates from the DSO for those NMIs.

This means that for a period of time, aggregators did not have all the DOE limits that applied to their portfolios.

INSIGHTS

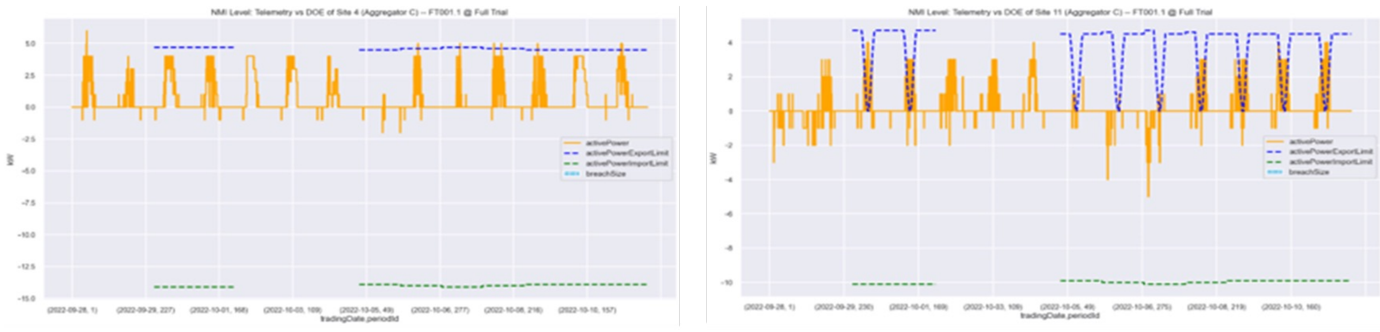
Coordination of new NMI enrolment and DOE updates

A coordination process will be needed between the active start date of new aggregator sites after enrolment with AEMO, and a corresponding DOE update from the DNSP.

In terms of NMI-level DOE conformance, the severity and duration of breaches was greater in constrained distribution network areas. This is illustrated in Figure 76. The yellow line shows the active power from NMI-level telemetry. The blue line reflects the DOE export limit. Results show network locations with higher constraints (the convex profile on the right) have more DOE breaches.

These areas are more likely to be rural, which experience less reliable internet coverage and consequentially more frequent communications outages for a VPP.

Figure 76 | Comparison of DOE breaches at non-constrained and constrained network locations



Flat profile
Network locations without much constraints and comfortable hosting capacity

Convex profile
Network locations with high constraints and insufficient hosting capacity at the sub-station

Accordingly, field test analysis focused on constrained dispatch intervals (5-minute periods where full import/export capacity was not available to all DER customers). Results showed approximately 13% non-conformance during constrained periods.

Table 12 shows DOE breach size for constrained intervals[213] over six months of data where all three aggregators were participating in field tests.[214]

Table 12: Field test results for DOE breach rate, sizes and durations for all aggregators

Metric	Result (rounded)
Breach rate	13% (among constrained 5-minute dispatch intervals, breaches occurred 13% of the time) Constrained intervals occurred ~7% of the time during the period analysed (October 2022 to March 2023)
Mean breach size	1kW Out of the 13% of breaches that occurred in constrained intervals, the majority were a breach size equal to or less than 1kW. Less than 5% were a breach size between 1 and 5kW. Among the constrained 5-minute intervals, breaches above 5kW occurred less than 1% of the time. This means that most of these DOE breaches were a result of feathering along the DOE limit. This behaviour may not have a material detrimental impact on the network. These field test results also indicate the active aggregators were generally able to conform to DOE limits (depending upon how industry ends up defining a DOE breach – i.e. what is the acceptable non-conformance threshold before it is considered a breach that attracts compliance enforcement action).
Mean breach duration	1.24 minutes

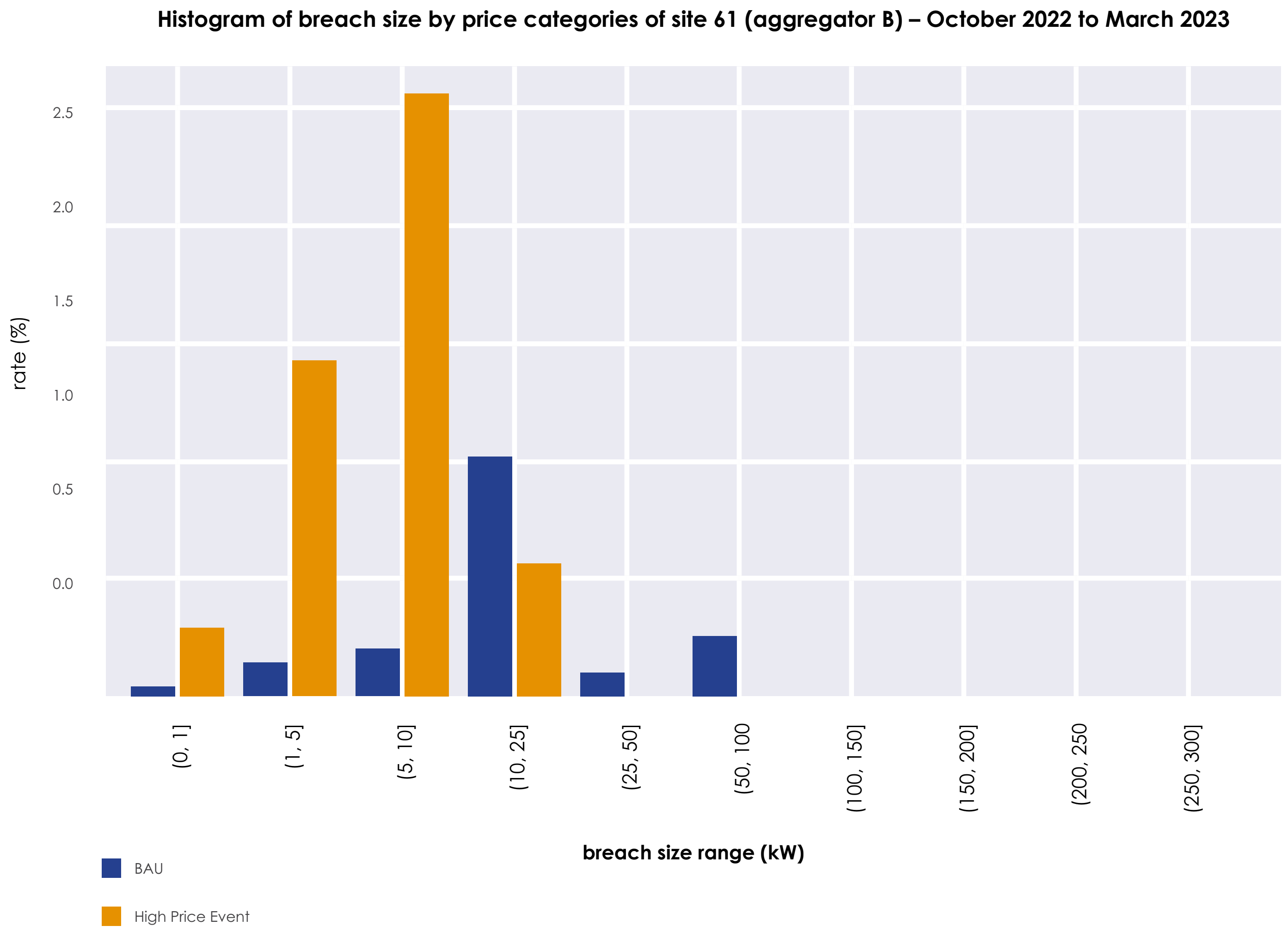
213 Occurrence of constrained intervals differed across NMIs and time periods. However, they generally occur during solar soak periods. Some NMIs may not experience constrained intervals at all if they are not in constrained parts of the distribution network.

214 This analysis excludes passive NMIs that may have breached DOE limits for a site.

Figure 77 shows results for the same 6-month period for the single site with the highest mean breach size. It compares breach sizes under benign wholesale market price conditions (defined for the purpose of analysis as between $0 and $300/MWh, blue bars) and high price events (greater than $1,000/MWh, orange bars).

Results showed the mean breach rate during high price events was 2.5%, with a breach size range of 5-10kW (i.e. during high price events, breaches with a size range between 5-10kW occurred 2.5% of the time). This compares to a mean breach rate of 1% and breach size range of 10-15kW during benign market conditions.

Figure 77 | Breach size by price categories for the site with the highest mean DOE breach size during field tests



The results for this site are indicative of general trends that found breach rates (across all aggregators during the same analysis period including both constrained and non-constrained intervals) occurred more often during high price events (~9%[215]) compared to benign market conditions (~2.5%).

Discussions with the three active aggregators identified factors contributing to DOE non-conformance. These included:

- Site uncontrolled load and controlled resource variability (due to weather, such as unexpected cloud cover that prevented use of rooftop PV and led to increased consumption from the grid, and behavioural factors, such as a change in customer consumption different from historical trends)
- Communications outages
- Customer manual over-ride.

215 This 9% represents DOE breaches during all intervals (not just constrained intervals) for all aggregators combined during high price events. The 13% in Table 8 represents DOE breaches during constrained intervals only, and all market conditions (i.e. both benign market conditions and high price events).

INSIGHTS

Improving DOE conformance is required in a wide-scale rollout of DOEs

Results indicate improving DOE conformance is required in a wide-scale rollout of DOEs so DNSPs can rely on DOEs to manage constraints and avoid the need for network solutions that add more costs to customers.

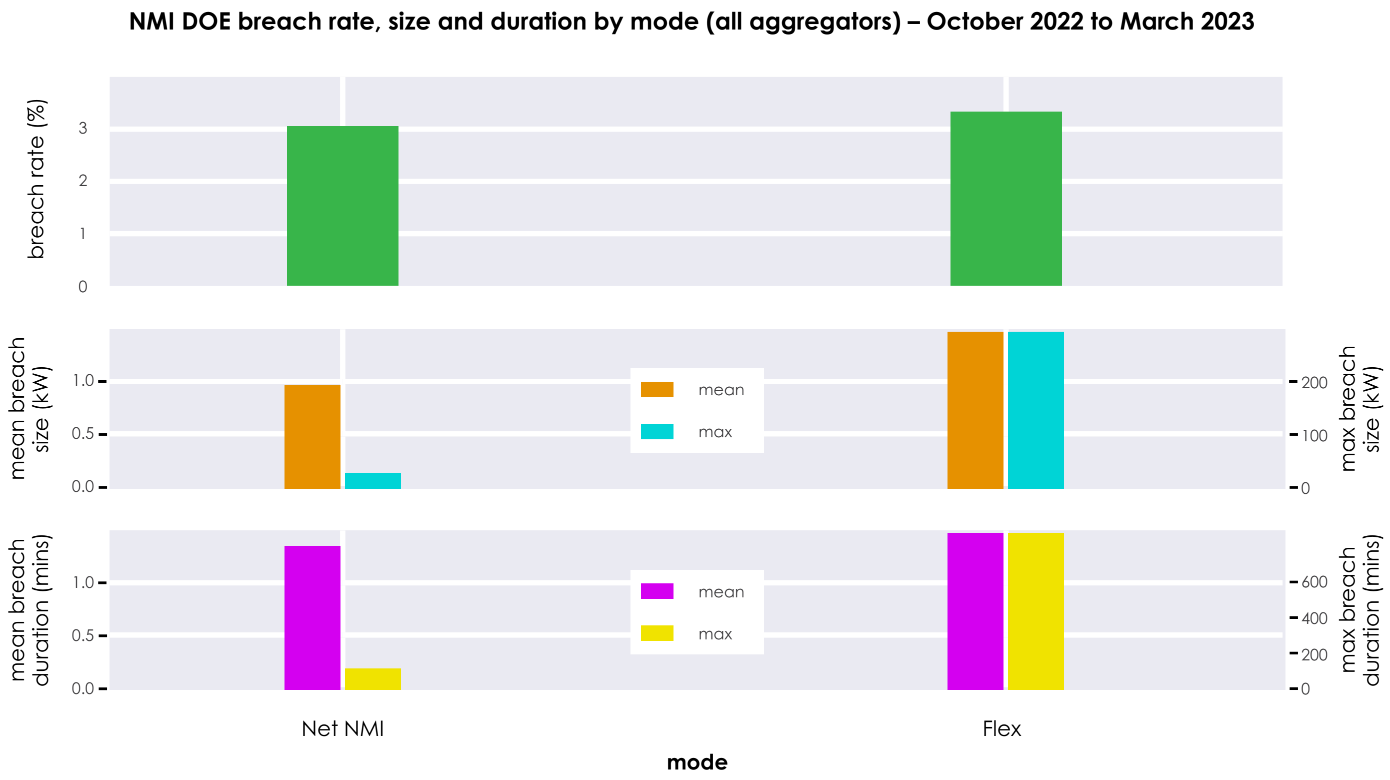
DOE conformance under Net NMI and Flex bidding

In terms of DOE non-conformance under Net NMI bidding and Flex bidding, results show there was no material difference.

Figure 78 shows:

- Breach rate (% of 1-minute intervals with a DOE breach across the field trial period where all active aggregators where participating – October 2022 to March 2023) (top graph, green bars)
- Mean breach size (kW) (middle graph, orange bars, left scale)
- Maximum breach size (kW) (middle graph, blue bars, right scale)
- Mean breach duration in minutes (bottom graph, purple bars, left scale)
- Maximum breach duration in minutes (bottom graph, yellow bars, right scale).

Figure 78 | Comparison of Net NMI DOE breaches under Flex and Net NMI bidding



While the maximum breach size and duration was higher during Flex bidding compared to Net NMI bidding, the mean values are similar across both bidding quantity definitions. There were more high-priced events during Flex bidding field tests, and this did not materially impact the difference in DOE non-conformance between the two bidding definitions.

INSIGHTS

Impacts of bidding quantity definition on DOE conformance

Results indicate the bidding quantity definition does not appear to have a material impact on DOE conformance. Aggregators were able to operate within network limits regardless of the bidding quantity definition.

CASE STUDY

Testing the event of an aggregator market exit

Project EDGE tested a real-world exercise of a participant market failure. This scenario was designed to test what impact an exit would have on demand forecasting and system operation, and in turn whether there is a requirement for an 'Aggregator of Last Resort' (AoLR) role and operating procedures.

The test design was based on the existing requirements within the Retailer of Last Resort (RoLR) operating procedures.[216]

The difference between a communication outage that could impact an aggregator DER fleet (be it the entire fleet or a large or small subset) and an aggregator leaving the market is important to understand, as the different scenarios rely on different technical responses at the device level. This scenario focuses on the former. The next case study focuses on the latter.

In the field trial exercise, AEMO issued a market notice that an 'AoLR' event had occurred. This triggered the following response (agreed with and applied to one aggregator):

- DNSPs ignore the exiting aggregator's NMIs when calculating the DOE and assume their DER are not controllable.
- The exiting aggregator's DER fleet is set to a default DOE export limit (received by the aggregator from the DNSP for each site on enrolment of each site).
- DNSPs calculate DOEs for the remaining active customers before the market exit.
- The lead-time applied was an 18-hour period between the aggregator notifying the market they cannot continue to operate and when they exit (the same time that occurs for a RoLR event).

The field test monitored the response of the devices, evaluated if the devices were capable of maintaining performance to the default DOE and considered the impact on real-time operations for the DNSP and AEMO. Conformance with the default DOE would require the DER to revert to a safe narrow operating band in the absence of controllability by an aggregator

The test demonstrated the importance of capturing default DOE values for each NMI on enrolment in a VPP and, if an AoLR event occurs, for this information to made available to AEMO so that the operating band of the exiting fleet can be managed around by dispatching other scheduled resources.

This would assist AEMO with maintaining accuracy of the demand forecast, which would be impacted by the decrease in generation expected from the AoLR's DER and the expectation it would not be controlled and no longer price-responsive.

Additionally, with the sites now operating as passive DER with a default DOE, conformance of these sites would need to continue to be monitored, as an aggregator is no longer present and responsible for the impacts any significant breach could have on the system security, local network integrity and AEMO demand forecasts. This conformance requirement and impact is one reason for the likely need for an AoLR market process.

An AoLR may also be required if the portfolio of the aggregator leaving the market is significantly large. For example, an aggregator of 100MW in DER capacity being removed from market and local services participation could leave a gap of up to 100MW of capacity for the system and networks.

The AoLR process would require the sites to de-register with their exiting aggregator and re-enrol with the AoLR aggregator. The trial did not explore the question of which market participant should be responsible for any AoLR role. The AoLR process would need to consider issues surrounding customer protections, such as the current services provided and the interoperability of devices to the AoLR aggregator to receive and act on DOEs and share telemetry.

The results also identified that there was a lag between when the aggregator is out of the market versus when the devices pivot to being passive.

CASE STUDY

Testing scenarios of major aggregator communications outages

Insights from the AoLR scenario in the above case study are also relevant to broader internet and communication outage scenarios. To mitigate operational risks, additional failsafe devices would be required to detect an outage to an aggregator's cloud and revert to default DOEs.

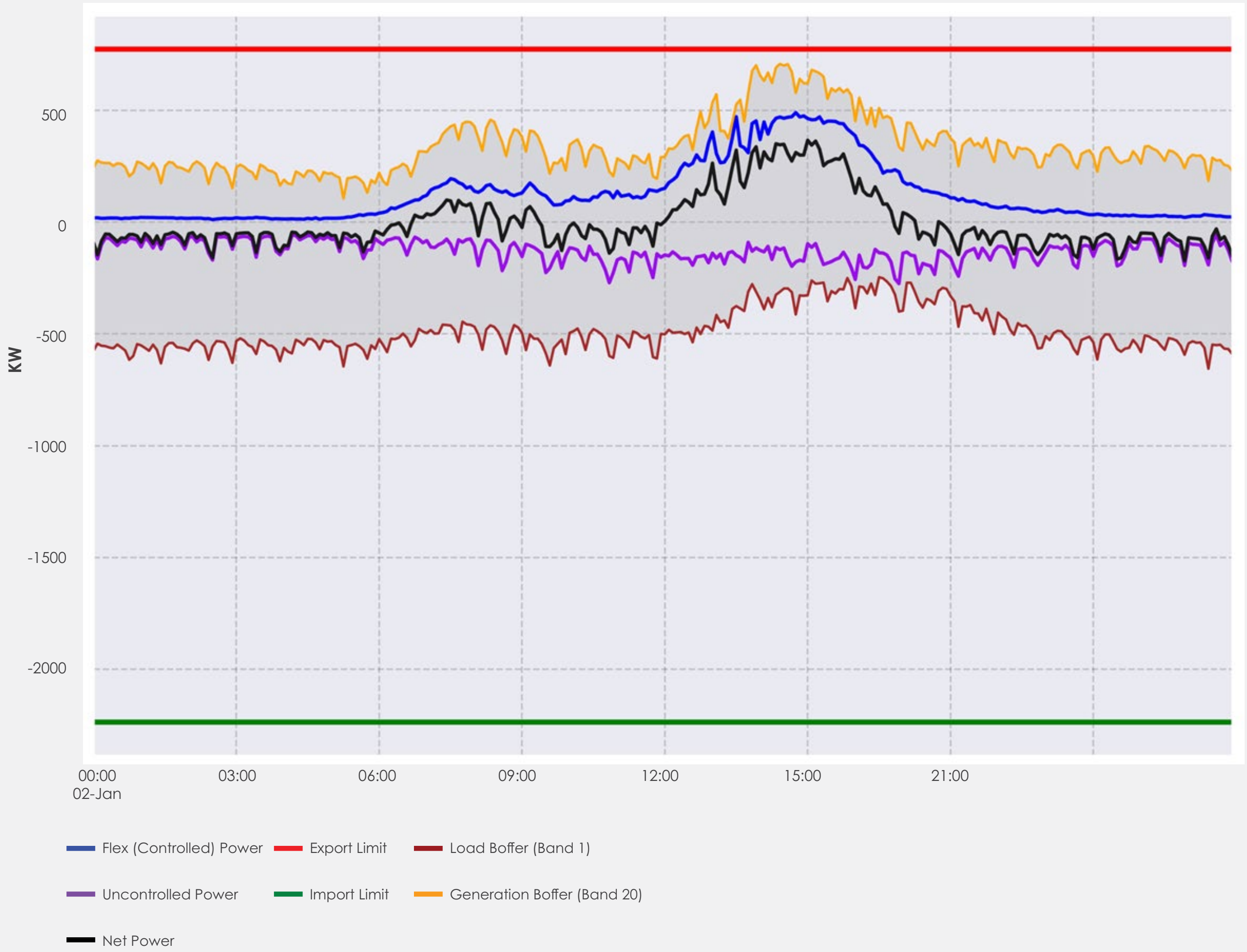
Scenarios were tested to analyse aggregators' market response to communications failures. Three scenarios were tested:

1. The aggregator could not communicate with a portion of its fleet. One variation impacted a portion of the total fleet; another impacted the entire fleet. The aggregator was required to continue to update its bids and offers every 5 minutes to reflect the available capacity of its fleet, including the operation of the separated NMIs within the default DOE limits set by the DNSP on enrolment.
2. The aggregator could not communicate with NEM systems; it could not receive dispatch instructions from AEMO and it could not submit bids and offers. It was required to follow the last dispatch instructions it had received.
3. The aggregator could not receive DOEs for 48 hours and had to revert to the default DOE limits set by the DNSP.

Figure 79 illustrates an aggregator's bidding response during scenario 1 (the aggregator could not communicate with its entire fleet).

216 AEMO. 2022. NEM ROLR Processes: Part A – MSATS Procedure: ROLR Procedures; Part B – BSB Procedure. https://aemo.com.au/-/media/files/electricity/nem/retail_and_metering/market_settlement_and_transfer_solutions/2022/nem-rolr-processes-part-a-and-part-b-v23.pdf?la=en

Figure 79 | Example of an aggregator's market response (bidding and dispatch performance) during a simulated communications outage scenario



The chart shows the aggregator's dispatch conformance when its whole fleet was disconnected and not receiving DOEs. The blue line reflects the Flex (controlled) power; the purple line reflects the uncontrolled power; and the black line represent the net power.

In terms of bidding behaviour, the aggregator did update its bi-directional offer so that its maximum available capacity (reflected by the highest price band, the yellow line) remained within the default DOE export limits (the thick red line).

While this example demonstrates the aggregator performed as required, overall, aggregators did not always perform as expected and required:

- Scenario 1: The aggregators did not always update the maximum capacity of their bids and offers to remain within the default DOE limits for the disconnected NMIs in their portfolio.
- Scenario 2: The aggregators did not always follow the last dispatch instructions it had received.
- Scenario 3: The aggregators did not always revert to the default DOE limit for the disconnected NMIs.

Key learnings were that aggregators would need to develop compensatory control capabilities to operate at a material scale to help manage power system security. These capabilities would need to include:

- Scenario 1: Processes to update their bids and offers so the maximum available capacity remains within the default DOE limits for the disconnected NMIs in their portfolio. Aggregators would also require compensatory controls to enable aggregators to continue forecasting their DER fleet
- Scenario 2: Controls to follow the last dispatch instruction. However, AEMO should engage with industry to consider the number of intervals to which such controls should apply to DER aggregators since it was observed in the field trial that aggregators' ability to respond to a sustained high quantity dispatch instruction diminished over time (see section 5.3.2.2).
- Scenario 3: Controls to revert DER to minimal export default limits, or the last DOE instruction until the next DOE was due to be received (assuming a set cadence), and then adopt the default limits if it was still unable to receive DOEs. This could be enforced by connection agreements requiring the implementation of appropriate control settings.

5.3.2.7 Communications and compensatory controls

Aggregators will need best practice communications and cyber security capabilities to ensure system security is maintained

During Project EDGE, aggregators experienced communications outages to DER fleets, which operate on public internet. Many DER fleets do not have communications redundancy (although some can use customers' internet and have 4G backup), which presents contingency scenarios and threat vectors that must be mitigated.

Aggregators will need to implement adequate cyber security requirements to ensure system security is maintained. This includes implementation of reliable fail-safes and fall-back default operations, including alternative mechanisms of DER fleet monitoring and control that do not share a common mode of failure.

Consistent application and visibility of compensatory control settings will be important for DNSPs and AEMO in a high DER future to understand the potential implications of widespread communications outages.

Discussions with aggregators in Project EDGE noted that they had some 'protect' measures to mitigate cyber security risks. However, they would need to improve their capabilities – including developing capabilities that that assume their system security has been compromised – to meet recognised industry best practice cyber security frameworks.

The USA Department of Energy's Cyber-Information Engineering framework provides guidance on building cyber security practices into the design life cycle of engineered systems to mitigate impacts of a cyber incident.[217] The framework emphasises practices that assume compromise. This drives requirements for appropriate detection, isolation, defending and recovery.

The Australian Energy Sector Cyber Security Framework (AESCSF) has been developed through collaboration with the Australian and jurisdictional governments and industry, including AEMO, the Australian Cyber and Infrastructure Security Centre, and representatives from Australian energy sector organisations.[218]

The framework leverages recognised industry frameworks while being tailored to the Australian energy sector. The framework is voluntary, and its purpose is to enable industry participants to assess, evaluate, prioritise and improve their cyber security capability and maturity. Aggregators should consider using this framework to develop their cyber security capabilities and inform the development of adequate compensatory controls.

There are scenarios (although not exhaustive) for which key compensatory controls will need to be developed by aggregators in the event of a communications outage and/or cyber incident:

- **Reducing export:** Connection agreements could require consistent compensatory control settings to revert DER to minimal export at an agreed ramp down rate.

217 Office of Cybersecurity, Energy Security, and Emergency Response, US Department of Energy. 2022, National Cyber-Informed Engineering Strategy from the U.S Department of Energy. https://www.energy.gov/sites/default/files/2022-06/FINAL%20DOE%20National%20CIE%20Strategy%20-%20June%202022_0.pdf

218 AEMO. N.d., AESCSF framework and resources. https://aemo.com.au/en/initiatives/major-programs/cyber-security/aescsf-framework-and-resources

- **Following the last dispatch instructions:** Compensatory controls would also be needed with regard to following the last dispatch instruction. The number of intervals to which this control would apply requires further consideration by AEMO and industry, recognising that batteries would eventually run out of charge.
- **Continued forecasting:** Another compensatory control would be the ability for aggregators to continue forecasting their DER fleet if there were partial communications outages. This also highlights the need for reliable longer-range forecasts.

These three scenarios were tested in Project EDGE (see section 5.3.2.6.)

Given the potential impact on system security of 'rogue' DER fleets in a high DER future, testing for conformance to compensatory controls settings may also be pre-qualification requirement for VPPs (to deliver different services) or become part of ongoing conformance testing.

5.3.2.8 An understanding of market requirements for scheduled resources

Aggregators will need time to develop sophisticated capabilities and design suitable systems for participating in the market as scheduled resources

In the Project EDGE field trial, aggregators did not always follow requirements that were intended to test and mirror market requirements.

In some cases, the inability to follow the field trial requirements was due to capability immaturity (which could be improved over time), such as not re-bidding lower quantities at extreme price bands to accommodate changing customer preferences for non-self-consumption responses.

In other instances, this was due to the aggregator not understanding the requirement or the need for the requirement. Two examples are outlined below: partial dispatch instructions and dispatch instructions to limit DUID gross power flow to zero.

Partial dispatch instruction

This field testing of a real-world scenario involved aggregators being dispatched by AEMO for 70% of their clearing bid for a set test window. All three aggregators conformed to full dispatch instructions (in line with their forecasts reflected in their bids) more often than to the partial dispatch instructions received from AEMO.

DEFINITION
What is partial dispatch?

In the NEM, partial dispatch occurs when a participant is dispatched for part of its bid quantity for a given price, potentially because it is the marginal resource in the merit order, or due to a binding constraint.

One of the aggregators noted partial dispatch was more challenging to achieve compared to full dispatch of bids in the trial. This was due to how the aggregator had configured its systems.

This aggregator forecasts dispatch according to four modes of operation based on different price points. The regional reference price (RRP) will determine the mode under which its NMIs operate. If the partial dispatch instruction does not fall within one of its four operational modes, it is challenging for the aggregator to follow the instructions.

All aggregators were wary of how the market requirement to follow dispatch instructions (including partial dispatch) could sometimes impact their ability to deliver self-consumption.[219] For example, if a partial dispatch resulted in a battery not being charged as desired, it could limit the aggregator's ability to capitalise on a future price event at a later interval, or conflict with a customer's desire for self-consumption later in the day.

An inherent responsibility for any participant representing customers in the wholesale electricity market is to manage their customers' risk and hedge accordingly. Aggregators could do this by adjusting the quantities offered at more extreme price bands (very high or very negative) so that more quantity is dedicated to fulfilling self-consumption at less risk of being partially dispatched.

219 AEMO. 2023. Dispatch Procedure. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705%20Dispatch.pdf

220 AEMO. 2023. Pre-dispatch procedure. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3704-predispatch.pdf?la=en

The NEM pre-dispatch process would support aggregators managing their dispatch. The pre-dispatch process has two key purposes:[220]

- Providing market participants with enough unit loading, unit ancillary service response and price information to allow them to make informed business decisions, including re-bidding to manage operational requirements
- Providing AEMO with enough information to allow it to fulfil its duties under the NER with respect to system reliability and security.

The process includes calculating and publishing pre-dispatch information of an aggregate nature (both input and outputs) to the market in the form of 30-minute schedules.

In future, aggregators will need to demonstrate capabilities to meet partial dispatch targets to be able to participate as scheduled resources.

The field test results for partial dispatch conformance reinforce other Project EDGE findings that a progressive, stepping-stone approach would facilitate building market maturity to understand participation requirements and design systems to meet those requirements before becoming scheduled resources (see discussion of the stepping-stone approach in section 5.3.1).

INSIGHTS
Understanding of market requirements will be a key aggregator capability

Results show future participants will need to understand the requirements of specific markets and services (for example, partial dispatch) to ensure systems and processes are developed to conform.

Field tests indicate that aggregators will need time to develop sophisticated capabilities for market participation and to develop robust understanding of market requirements for dispatchability.

Management of minimum system load events through DOEs or AEMO directions

Project EDGE undertook several field tests with the objective of demonstrating whether the DOE framework could assist AEMO in managing system security and reliability during scenarios such as minimum system load (MSL3) events and distributed PV contingency events (DPV-C).[221]

These tests also assessed the maturity of the aggregators' technical capabilities to restrict exports of energy into the grid despite having the incentive of high wholesale prices ($15,000/MWh) to export as much as possible.

Table 13 outlines DPV-C management considerations in a high DER future. The table includes current arrangements (Market Notifications) and the various DOE and aggregator bidding approaches contemplated through the field trial.

221 AEMO. 2021. MSL & DPVC Market Notices - FAQs. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/cmsl-faqs.pdf?la=en

Table 13: DPV-C management considerations in a high DER future

No.	Testing approach	Implementation options	Summary of outcome
1	Market Notifications (received by DNSPs and aggregators) Project EDGE tested the current defined market process	MSL 1 – Advance notice of possible event to manage the risk of rooftop solar PV disconnecting at the same time as a large power station and/or minimum system load MSL2 – Confirm operational actions taken MSL 3 – Notify that curtailment of rooftop solar PV is occurring[222]	This process for managing a 'lack of supply' is being mirrored for scenarios when there is a 'surplus of supply' at times of stress on the power system. AEMO would be asking for help to manage these events and communicating what actions are being taken. These forecast imbalances between supply and demand (LoR and MSL) are designed to warn the market, giving the market time to respond and for it to be reflected in their bids/offers/forecasts. If the market doesn't respond and/or the forecast remains that there is still an imbalance, then the next stages of the scheme would be actioned culminating in curtailment activities in MSL3/LoR3.
2	DNSP Net NMI DOE This use case was tested in Project EDGE during market suspension See the case study in this section	Set net export limit = 0	Generation would be partially reduced. Some generation would still occur as distributed PV may be servicing uncontrolled and controlled loads. DOE breaches may occur due to uncontrolled load forecast errors.
3	DNSP Net NMI DOE This could not be tested in Project EDGE due to implementation of the DOE scheme This use case was unavailable due to construction of two DOE limits, both required to be positive (import and export limits => 0 (equal to or greater than 0)) See the discussion in the case study in this section regarding how the implementation of DOEs prevented this use case	Set net export limit <= (less than or equal to) forecast uncontrolled load and controlled loads (as a negative value)	Generation would be partially reduced. Some generation would still occur as distributed PV may be servicing uncontrolled and controlled loads. DOE breaches may occur due to uncontrolled load forecast errors.
4	DNSP Flex DOE This use case could not be tested in Project EDGE because Flex DOEs were not implemented and field tested	Set Flex generation limit = 0	Generation would be partially reduced. Some generation may still occur as distributed PV may be servicing controlled loads. DOE breaches would be less likely to occur due to full control of the devices.
5	DNSP Flex DOE This use case could not be tested in Project EDGE because Flex DOEs were not implemented and field tested	Set Flex generation limit <= (less than or equal to) forecast controlled loads (as a negative value)	Generation could be fully reduced however there could be increased load. DOE breaches may occur if controlled loads were unavailable (e.g. batteries were already charged). However, the breaches would be technical in nature and unlikely to impose risks on the network operation (e.g. the outcome for setting a negative value would be to reduce generation not to manage a local import/load constraint).
6	Aggregator bidding (at AEMO direction) This use case was tested in Project EDGE	Net portfolio bidding = 0	Generation would be partially reduced. Some generation may still occur as distributed PV may be servicing uncontrolled and controlled loads. DOEs must be followed for all bids including coordinated directions from AEMO (e.g. only one approach would be triggered). If more than one approach were to be used, care must be taken to ensure DOEs are not breached. Only customers participating with aggregator VPPs would be activated.
7	Aggregator bidding (at AEMO direction) This use case was tested in Project EDGE market suspension	Flex Portfolio bidding = 0	Generation would be partially reduced. Some generation may still occur as distributed PV may be servicing controlled loads. DOEs must be followed for all bids including coordinated directions from AEMO (e.g. only one approach would be triggered). If more than one approach were to be utilised, care must be taken to ensure DOEs are not breached. Only customers participating with aggregator VPPs would be activated. Solar customers outside of VPPs not would not be managed.

222 AEMO. N.d., Fact Sheet: Operating the grid with high roof-top solar generation. https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/consumer-fact-sheet.pdf

CASE STUDY

Constraining system output by setting all NMI DOE net export limits to zero

This case study illustrates how aggregators may perform regarding DOE conformance when operating in the context of extreme price events.

During the field test, AEMO sent 0MW VPP portfolio export limit instructions to the DNSP (in practice, this would be via the TNSP)[223] to convey to aggregators through DOEs.

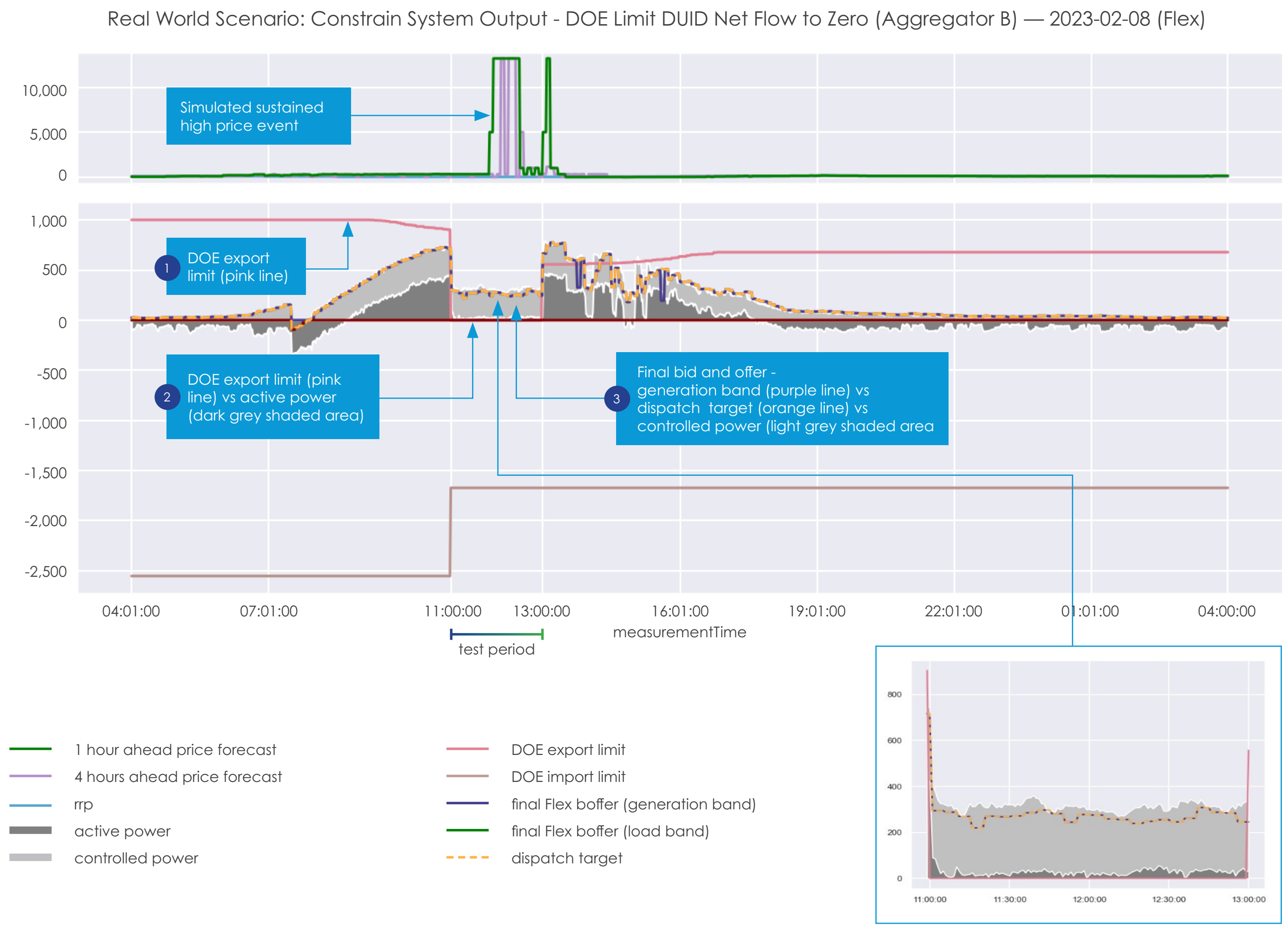
The DNSP was required to apply DOEs so that aggregators would need to respond by constraining energy output to zero export (net) for their portfolios as a whole (not necessarily individual sites). The DNSP implementation set all NMI DOE export limits to 0kW.

To achieve this, aggregators needed to coordinate their portfolios for exporting NMIs to achieve net zero exports or net load for those NMIs. In other words, aggregators needed to operate their DER to a state where the DER could not export energy back to the distribution network.

Figure 80 shows the performance of one aggregator during the field tested event, testing approach No. 2 in Table 13 (DNSP Net NMI DOE - set net export limit = 0).

223 Under existing manual load shedding procedures, AEMO directs a TNSP in accordance with load shedding procedures applicable to each relevant NEM region. These procedures are confidential and provided to TNSPs and Jurisdictional System Security Coordinators (JSSCs – a Ministerial-appointed role responsible for preparing a load shedding schedule to determine the sequence of load shedding and restoration. Contingency plans need to be agreed among parties involved in the execution of the plan (typically AEMO, TNSPs, DNSPs and generators). Where necessary, the relevant TNSPs and DNSPs will need to agree on the plan. After a TNSP control room receives communications from the AEMO control room, the TNSP will communicate with the relevant DNSP control room to coordinate the required load shedding.
AEMO. 2023. Power System Security Guidelines. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf?la=en

Figure 80 | Field tested market event demonstrating an aggregators' ability to conform with DOEs during extreme price events



Box 1 in the figure shows that the sum of all NMI DOE export limits for one aggregator's portfolio were set to 0kW for the test period. Box 2 shows whether the active power (net - dark grey shaded area) for the aggregator's portfolio conformed with the 0kW DOEs.

The break-out box on the top right of the figure zooms in on the test period to show results for active power conformance against the DOE export limit. The zoom-in shows that for most of the test period, net load (negative active power) or no export (0kW active power) were not achieved (the dark grey shaded areas mostly exceed the pink line representing the DOE export limit.

Less than 1% of intervals resulted in net load or no net export. The average breach size during the test period was about 31kW. Results relating to bidding behaviour (box 3) are discussed around Figure 84 later in this section.

Although non-conforming against the strict trial definition of 'DOE breach',[224] the aggregator performed relatively well considering the conflicting incentive of the high wholesale price.

The figure shows that the aggregator was generally able to successfully constrain DER net output close to zero and that the gross generation (light grey shaded area) was not zero, providing energy for self-consumption at the customer premises (by the uncontrolled load). This was confirmed via analysis on the controlled load and generation telemetry data from the aggregator, discussed below.

224 For the purpose of the results discussed in this section, a breach was defined to mean performance that did not exactly match the DOE allocated to a particular site. This means, performance 0.1kW outside of the DOE limit resulted in a breach. This may not be how industry chooses to define a DOE breach. And the use of a strict definition of a breach in the field test results analysis does not indicate industry should define a DOE breach in the same manner.

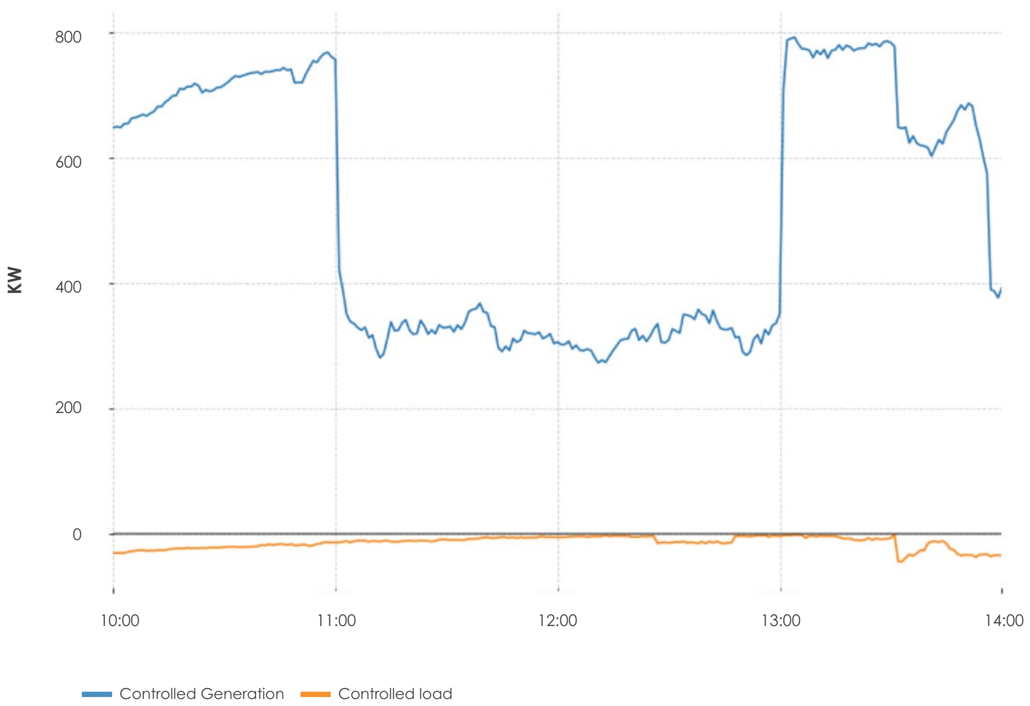
INSIGHTS

Field trial findings on aggregators coordinating DER to limit exports while providing additional services

This aspect of the trial has an important benefit as it demonstrated how an aggregator can operate DER that limits the export of energy back into the network, while providing consumers with additional services (self-consumption).

However, the amount of DER actually online and generating must be understood by the networks and AEMO, and the amount of load being served by the DER under this model is invisible to these parties. The actual load makeup for the aggregation during this test is shown in Figure 81.

Figure 81 | An aggregator's load and generation makeup of their response for a DOE target of zero in field tested event



Zero net NMI DOE export limits could be utilised for distributed PV contingency (DPV-C) events. to mitigate some, but not all, of a DPV-C (as seen in the controlled generation that is still operating to service uncontrolled load in Figure 80 above). These events involve the risk of distributed PV tripping off alongside a large-scale generating unit, where this total loss of energy combines to a level above the amount of reserves to manage such an event and keep the power system secure.[225]

In these scenarios, there is a need to reduce the amount of distributed PV generation in the power system and not just increase load to raise minimum operational demand, as this may not reduce the DPV contingency size.

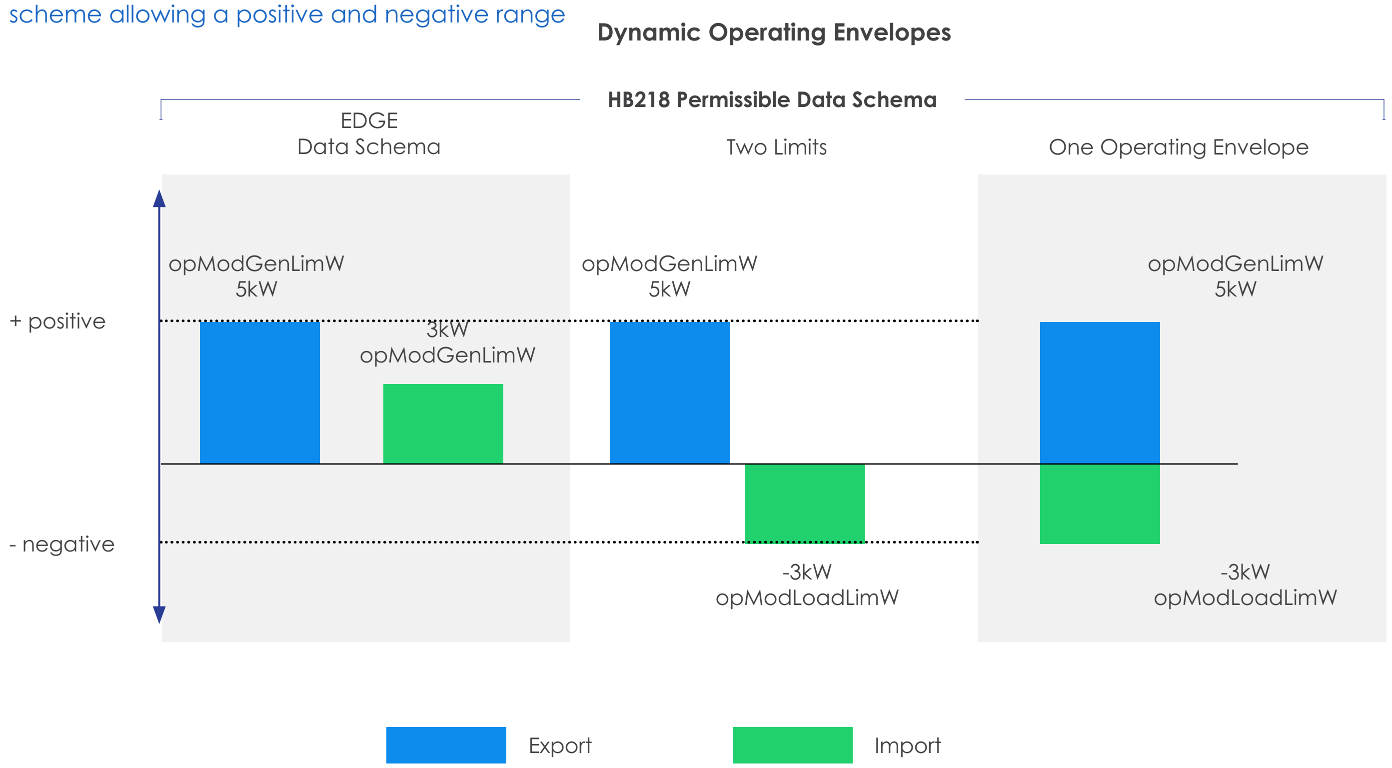
For Net NMI DOEs to be harnessed in a manner that curtails the full amount of distributed PV generation (so the DER is not also powering the premises as in Figure 80), the DOE export limit would need to be negative (e.g. -5kW) and set to greater than or equal to the forecast uncontrolled load (e.g. -5.1kW where uncontrolled load is –5kW).

In turn, the aggregator would reduce the DER generation below the self-consumption level, thus resulting in DER generation across the fleet being reduced to zero.

This application of DOEs could not be tested with the design limits of the Project EDGE implementation of the CSIP-AUS data schema, where export and import limits had to be positive numbers.[226] This effectively implemented two separate and independent limits.

The Standards Australia Handbook for the Australian implementation of CSIP-AUS227 has considered that these limits can be set as either positive or negative numbers, thus providing one operating envelope that covers export and import limits, as depicted in Figure 82.

Figure 82 | Comparison of the Project EDGE data schema implementation of DOEs and the CSIP-AUS permissible data scheme allowing a positive and negative range



225 AEMO. 2021. MSL & DPVC Market Notices – FAQs. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/cmsl-faqs.pdf?la=en

226 Project EDGE. 2022. Project EDGE Data Specification: - Part B: Market Participation & Operational Visibility Data Requirements, p 30. https://aemo.com.au/-/media/files/initiatives/der/2022/edge-data-specs-part-b.pdf?la=en

227 The Standards Australia handbook of CSIP-AUS (more formally known as SA HB 218:2023) is available for free on the Standards Australia store website. Standards Australia. 2023. SA HB 218:2023: Common Smart Inverter Profile – Australia with Test Procedures. https://store.standards.org.au/product/sa-hb-218-2023

This is significant because it would enable an alternative approach for DPV-C management (approach No. 3 in Table 13).

A negative DOE could be used during MSL events, and the negative value would be the limit that DER would need to follow. This could provide a stronger DPV-C management control because generation could be fully reduced. A management control where net export limits are set to zero would only partially reduce generation.

Nonetheless, under both approaches, some generation would occur as distributed PV may be servicing uncontrolled and controlled loads. Accordingly, both approaches create issues with conformance to DOEs when there is additional generation at the site, such as an EV or a battery, that is not under the operation (control) of the aggregator managing the DOE and distributed PV and due to uncontrolled load forecast errors.

An alternative to using net NMI DOEs to reduce the gross generation on the power system could be applying DOEs to only the sum of the flexible assets (Flex DOE) (see discussion in section 4.3.7).

This would theoretically provide additional distributed PV curtailment capabilities (noting Flex DOEs were not field tested in Project EDGE) without impacting the operation of customers' uncontrolled devices.

It should also be noted that, in the case of Flex DOEs, there could be controlled generation turned on that is being self-consumed by controllable loads. However, since the aggregator has control of both load and generation, the risk of uncontrolled load creating Flex DOE breaches is managed.

INSIGHTS

Field trial findings on aggregators coordinating DER to respond to a change in DOE limits

Overall, the results from the simulated market event show that aggregators do have the potential to control their DER portfolios to deliver a step change response to a change in DOE limits. However, work will be needed to build capabilities over time to better meet DOE conformance consistently.

In particular, DOE conformance in constrained areas would need to be improved in a wide-scale rollout of DOEs. Work would also be needed to assess if and how the DOE framework could be used for operational coordination between AEMO, TNSPs and DNSPs to manage MSL and DPV-C events.

CASE STUDY

Constraining system output through dispatch instructions

In the NEM, security constrained economic dispatch (SCED) is used to ensure the market is dispatched within the secure limits of the system. In a high DER future, coordinated DER would participate in the wholesale dispatch process (which used SCED).

There may be times when standard market and system operating tools (e.g. SCED) are unable to keep the power system secure. In those scenarios, AEMO needs to intervene in the market to maintain system security outside of the security-constrained economic dispatch process. However, this is a last resort when preceding actions and operating tools have not been enough.

Accordingly, there will be times when aggregators will be issued instructions to constrain system output to manage system security risks. During system events, aggregators may be required to:

- Restrict grid export of energy to ensure operational demand is high enough for a secure and reliable power system (minimum system load (MSL event)
- Finding additional export capacity from their portfolios by turning off DER devices loading (lack of reserve (LoR2) event)[228]
- Under a distributed PV contingency event, restrict PV generation while not adjusting operational load (only reduce generation) via DOEs (see Case study: Constraining system output by setting all NMI DOE net export limits to zero for a discussion of results in terms of conformance in this scenario using the DOE framework).
- Meet specific dispatch targets under a market suspension. This was tested in Project EDGE during the declared market suspension in the NEM in June 2022 to learn from this rare event. Some of the key insights from the tests were:
  - Aggregators were able to meet AEMO intervention targets when directed.
  - The DNSP was able to calculate DOEs to achieve a set point under certain conditions. However, DOEs alone may not elicit an aggregator response that is as accurate as dispatch instructions (since they provide a permissible limit, rather than specific instructions.

In designing directions to VPPs in future, coordination will be needed between AEMO, TNSPs and DNSPs to ensure dispatch targets provided to VPPs are able to be achieved with the DOEs provided by the DNSP.

See the Project EDGE Lessons Learnt Report #2 for details on the test and other key insights.[229]

To test capabilities and performance under MSL and distributed PV contingency events, Project EDGE conducted several scripted scenarios in the field to demonstrate aggregator capabilities to operate and respond to minimum system load scenarios and distributed PV contingency events.

All participants agreed to explore an alternative approach to only using DOEs to enable distributed PV management and also test aggregator capabilities to operate and respond to AEMO directions.

This involved active management of DER via bids and offers and via a dispatch instruction as part of the existing market mechanism tested in Project EDGE.

During one field test, aggregators were issued dispatch instructions for 0kW in flex mode (only controllable DER capacity was dispatched, not uncontrolled load or generation).

The objective of this test was to help understand how MSL events could be managed through directions if needed (noting there may be times that generation should turn off rather than reduce to 0kW export, as discussed at the beginning of this section 5.3.2.8.

During all intervals within the test period, none of the aggregators' controlled power met the dispatch target. This is demonstrated in Figure 83 showing one aggregator's dispatch target (orange line) and controlled power (grey shaded area).

The test period was 09:00 hour to 11:00 hours (the area within the dashed vertical lines where the orange line is at 0kW), but the grey shaded area exceeds 0kW230 (consumption). The top graph also shows the 1 hour and 4 hours ahead price forecast, and the RRP during this event. In this scenario, there was a correlation between the price and the controlled power: as the price decreases, there is an initial increase in consumption to capitalise on the price despite the 0kW dispatch instruction.

Consumption continues even as the price increases (but remains negative) which is not in conformance with the dispatch instruction, but curtailing flexible generation is still a better outcome for grid and DER customers than using emergency curtailment under a MSL scenario.

However, the better outcome result would not be guaranteed by this approach. Therefore, the key lesson learnt is that if directions are used for VPPs to manage MSL events, a 0kW dispatch instruction to limit PV generation may not achieve the intended outcome of helping alleviate the MSL conditions. Other methods other than directing zero portfolio output will need to be explored for aggregators to bring on more load. For example, AEMO should consider issuing directions:

With the knowledge of DOE limits so that it is cognisant of the potential variability if the aggregator does not conform

That consider the aggregator's forecast capacity (to understand what load is achievable – this would depend on reliable forecasting, see section 5.3.2.1), updated to reflect DOE limits provided by the DNSP.

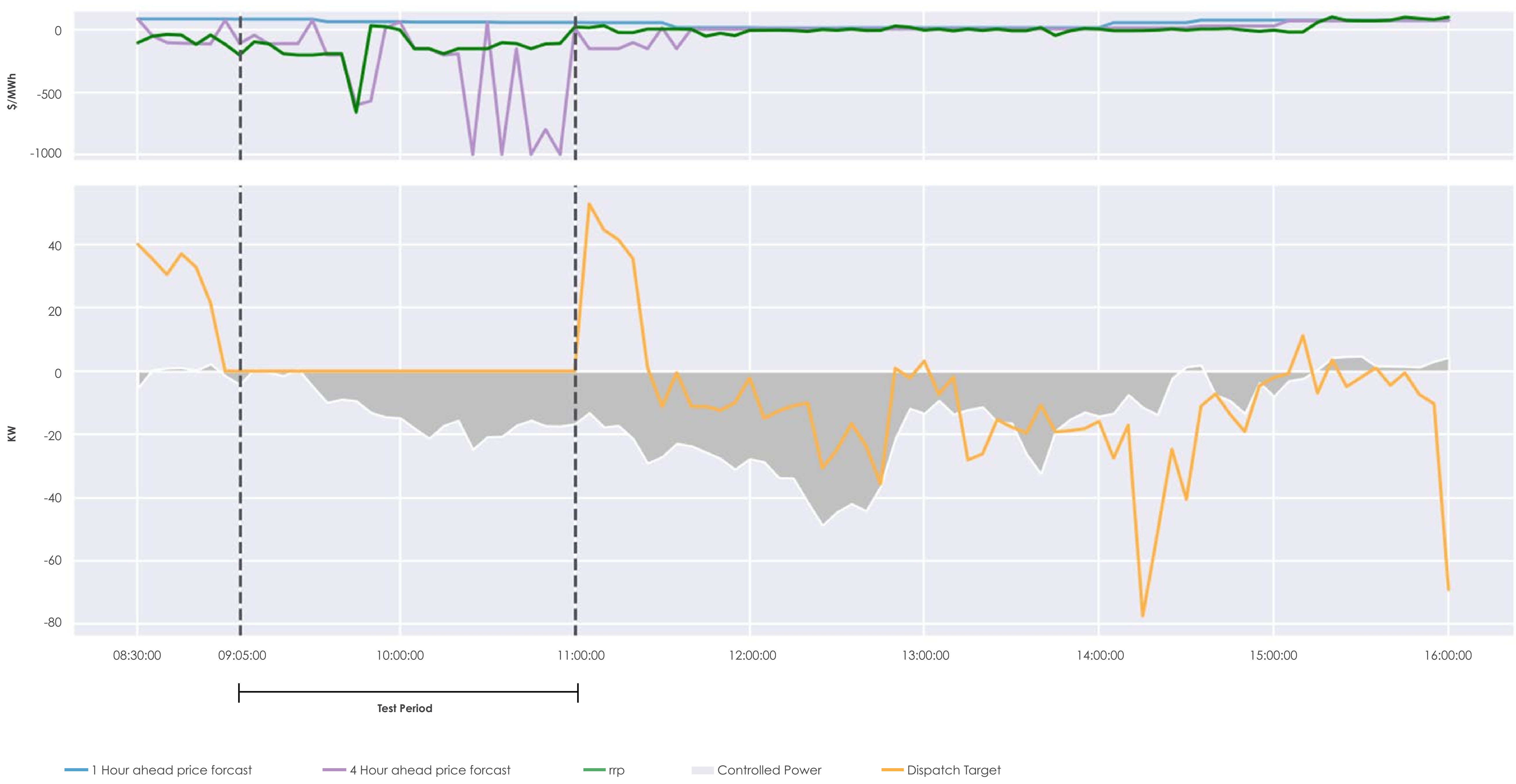
Targets that provide a set load would be a better method to achieve the intended outcome to alleviate a MSL event, as it would remove variability.

228 An LOR2 event signals a tightening of electricity supply reserves. If a forecast LOR2 event is declared, AEMO has the ability to direct generators or activate the RERT mechanism to improve the supply demand balance. AEMO (2022) Lack of Reserve (LOR) notices: Fact Sheet. https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf?la=en

229 AEMO. 2022, Project EDGE Lessons Learnt Report #2 November 2022. https://aemo.com.au/-/media/files/initiatives/der/2022/project-edge-lessons-learnt-2--final.pdf?la=en

230 While it appears that there are intervals within the test period where the controlled power is at zero, and therefore aligning with the dispatch instruction, this is due to the scale of the graph. No intervals met the dispatch target of 0kW. The controlled power ranged from 0.42kW to 24.66kW.

Figure 83 | Results for Aggregator A during a constrain system output field tested scenario



Overall, results across the aggregators indicated they would benefit from additional time to develop capability to consistently act on directions.

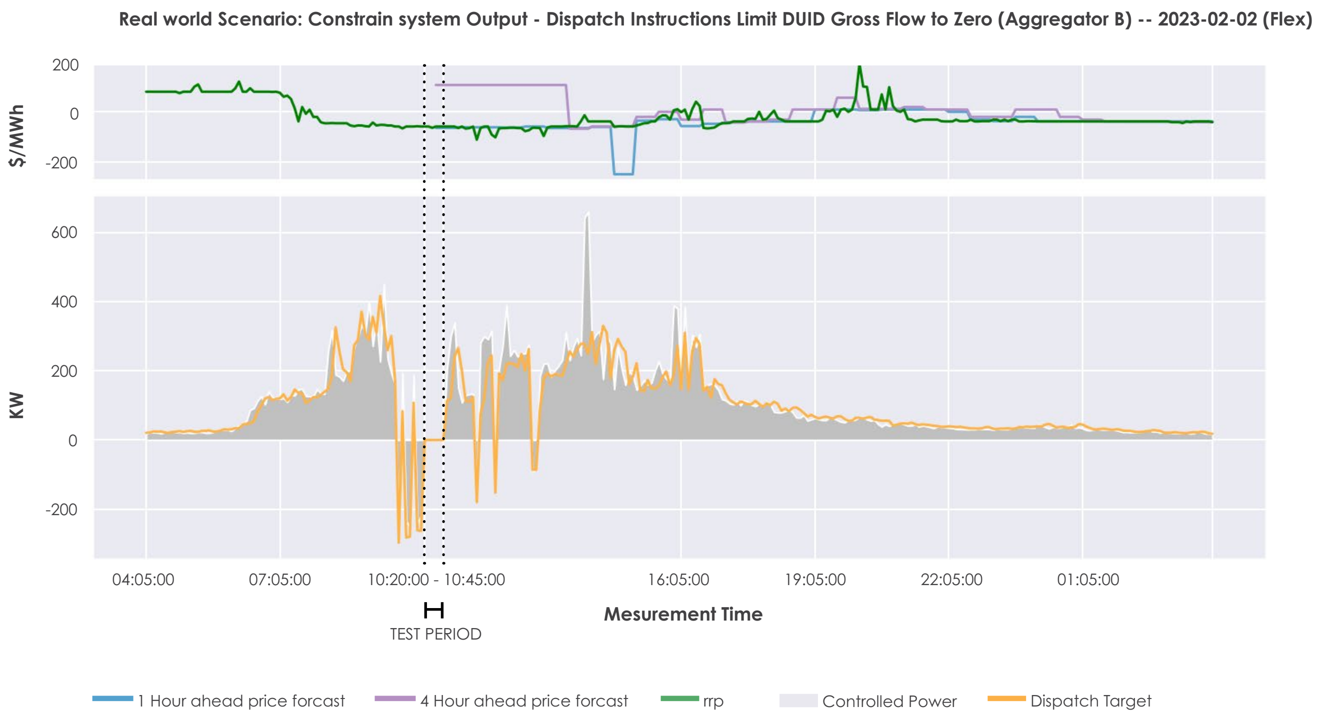
The results also suggest that to maintain system security, expected responses to system events should comprise part of aggregator performance testing (during the registration process) to demonstrate that aggregators have the necessary capabilities to participate in the wholesale market.

In case there is an absence of enough reliable VPP response, other mechanisms should be developed; for example, MSL notices instructing generation is turned off or emergency backstop mechanisms.

While the results or discussions with aggregators do not suggest deliberate failure to comply with the dispatch instructions, they were not subject to actual market incentives and penalties in the trial.

Figure 84 shows good performance in another example, also with Flex bidding, under which the aggregator actively managed the sum of the sites' generation and controllable load to provide a net controlled position that equals zero.

Figure 84 | Results for Aggregator B during a constrain system output field tested event using dispatch targets to achieve a DUID gross flow equal to zero



The figure shows that during the test period Aggregator B was able to successfully reduce the net of actively managed devices to equal zero. Figure 84 illustrates this further by showing the makeup of the controllable load and generation were both switched off.

Compared with the results for Aggregator A shown in Figure 83, this provides an example of the value of aggregator capabilities to control both generation and load simultaneously to achieve a desired outcome at any dispatch quantity (with performance being assessed against telemetry for the controlled resources only; that is, excluding uncontrolled load).

Figure 85 | The aggregator's load and generation makeup of their response for a dispatch target of zero

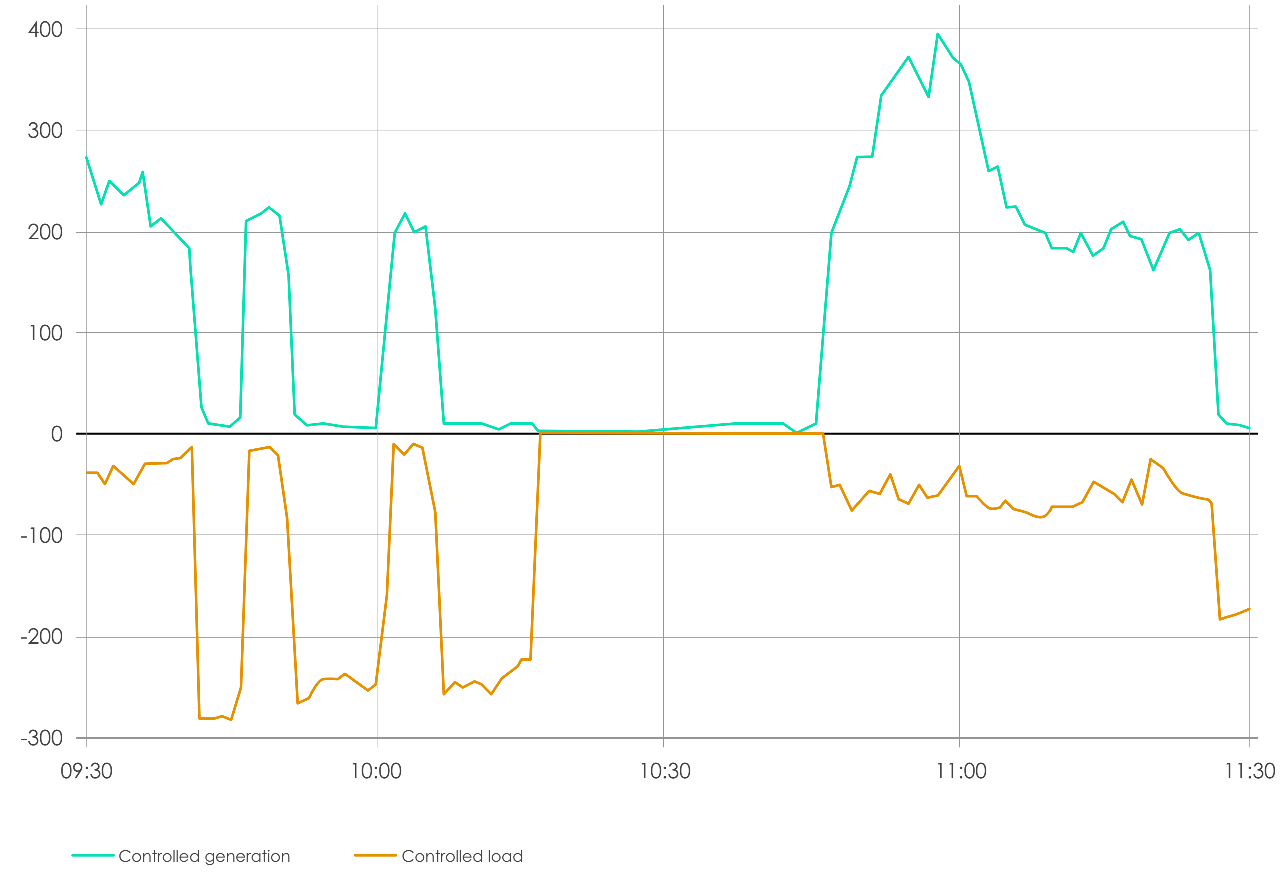
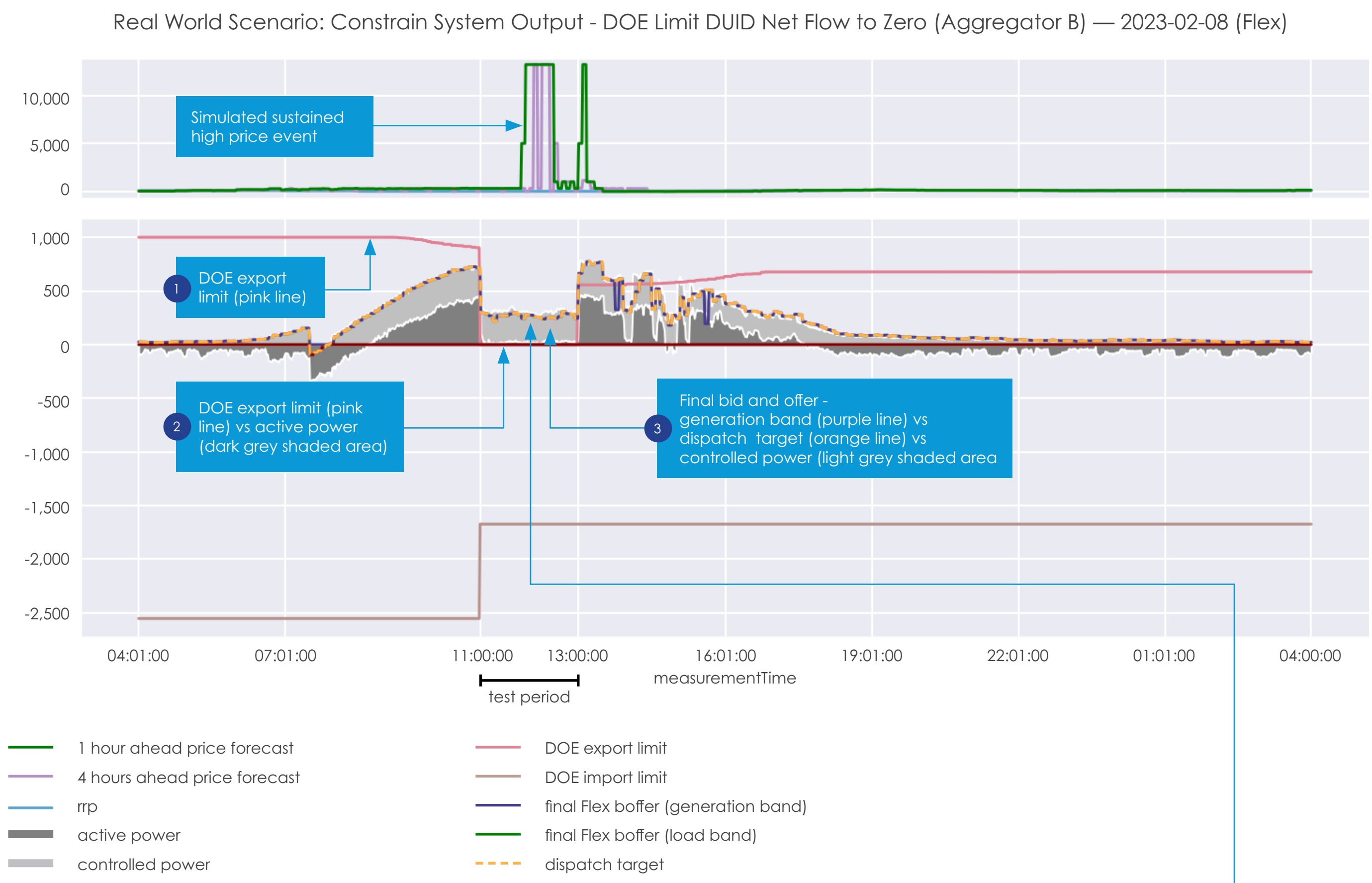
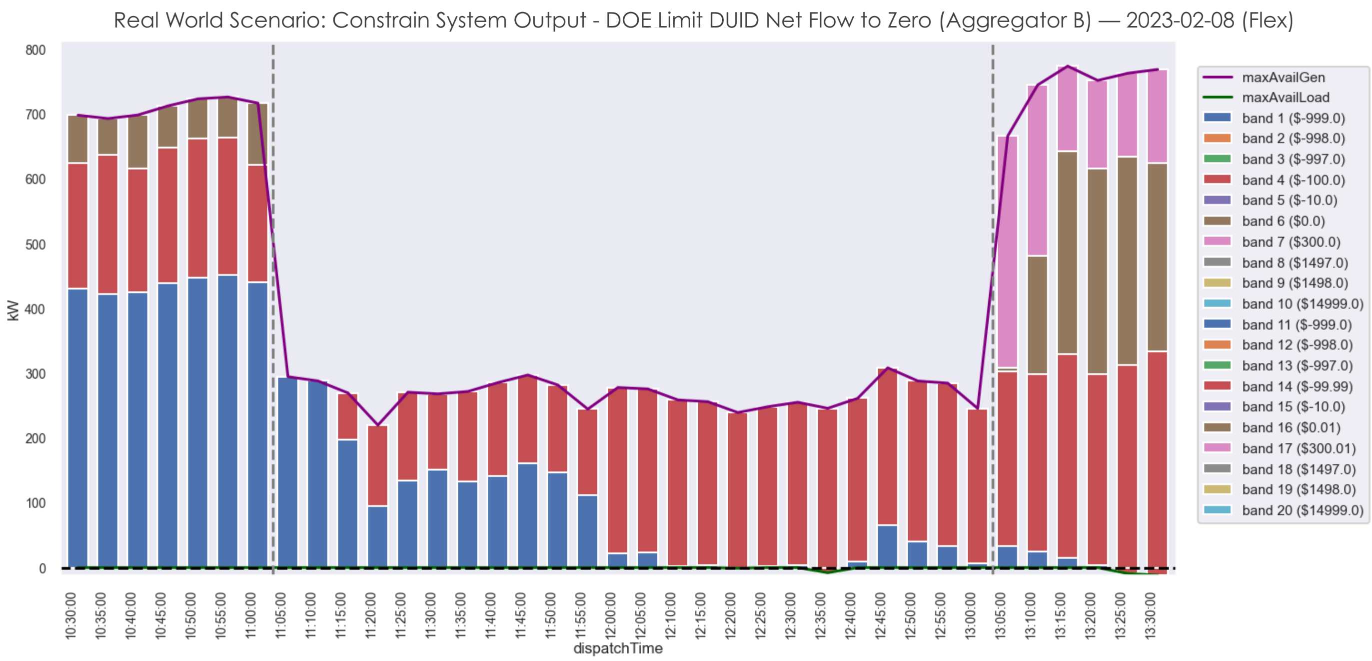


Figure 85 shows the performance of one aggregator that was allocated a DOE requiring it to constrain energy output to zero export (net NMI) for its portfolio. The objective was for the aggregator to operate DER to a state where they were not exporting energy to the distribution network.

The performance in terms of DOE conformance for this example is discussed around Figure 78 in section 5.3.2.6. The discussion here focuses on the aggregator's performance in terms of bidding and dispatch.

Figure 86 | Simulated market event demonstrating an aggregators' ability to limit DUID net flow to zero





This chart shows how the bidding intention was subsequently delivered with the Flex dispatch instructions (yellow line) closely aligning to the aggregator's actual fleet behaviour (coordinated DER power flow - light grey shaded area) while simultaneously conforming to Net NMI DOE limits (pink line and dark grey shaded area).

As discussed in section 5.3.2.6 around Figure 78, less than 1% of intervals achieved net load (negative active power) or no net export (0kW active power). However, in terms of the aggregator's bidding performance and behaviour to control the DER in its portfolio to achieve the test objective, the results indicate the aggregator had the capabilities necessary to operate under these test conditions.

INSIGHTS

Field trial findings on aggregator capabilities to respond to power system event

The results from these field scenarios indicate VPPs need to develop a thorough understanding of the required capabilities and obligations for market participation. Provision of simple information to support new entrants in this process can accelerate conformance.

Results also indicate that expected responses to power system events should comprise part of aggregator performance testing during registration to demonstrate that they have the necessary capabilities to participate in the wholesale market. In case there is an absence of enough reliable VPP response, other mechanisms should be developed. For example, MSL notices instructing generation is turned off, or emergency backstop mechanisms.

5.3.2.9 Service co-optimisation and value stacking

Aggregators will need capabilities to manage scheduling conflicts and optimise services in cooperation with AEMO and DNSPs

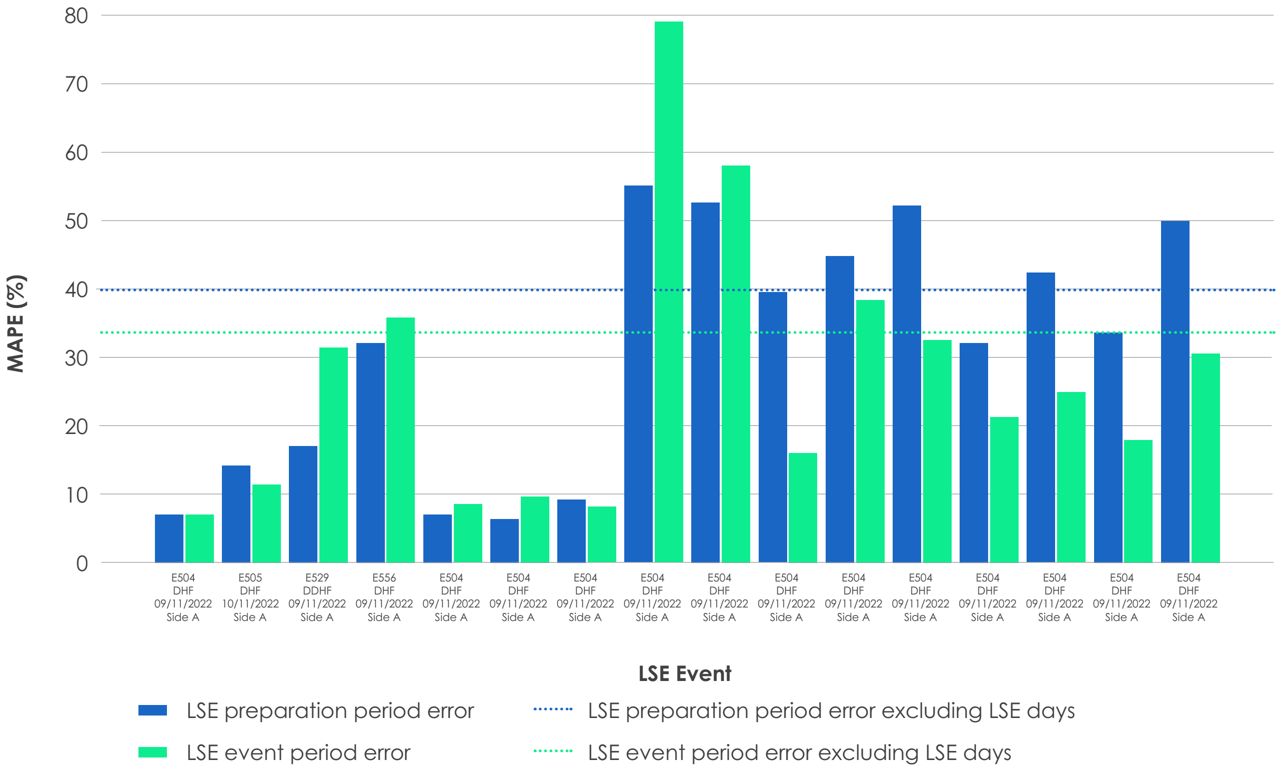
Analysis of field trial data sought to understand whether the provision of local NSS impacts wholesale dispatch conformance.

Figure 87 shows that, generally, dispatch conformance during NSS preparation periods, and during an NSS event period, was not impacted detrimentally. Local NSS preparation periods refer to the time period between the aggregator receiving the arming signal from the DNSP and the delivery activation signal. See 7.3.2 for a discussion on the NSS preparation and delivery process and field trials and results.

For high firmness services, an arming signal is the notice for the aggregator to prepare their fleet for the NSS event.[231] The delivery activation signal is a confirmation notice that local network service delivery is required by the DNSP at the agreed time, volume and duration.

231 Low firmness services do not have an arming signal; rather, the services require the aggregator to provide as much as they can for as long as they can within the LSE event duration timeframes.

Figure 87 | NSS impacts on wholesale dispatch conformance



The blue and green bars represent the average error during the NSS preparation and NSS event periods respectively. The lines are the average dispatch conformance error observed in the same time duration of when an NSS preparation (blue line) and NSS event (green line) occurred.

As an example:

- An NSS preparation (periods covered by the blue bars) occurred between 7am and 11am.
- The analysis compared:
  1. the average error observed in wholesale dispatch conformance during an actual NSS preparation event between 7am and 11am; and
  2. the average error observed across the trial at between 7am and 11am excluding the days when the actual NSS event was scheduled.

This provides an understanding of whether the error increased or decreased during the interval with NSS commitments compared with similar intervals of only wholesale market participation.

Ideally, the bars should be below the lines to indicate dispatch conformance error during NSS was not worse than average dispatch conformance.

While there were NSS events during which dispatch conformance error was higher than average, the sites that had the highest error (the green bars above the green line) were C&I sites. Events with the lowest error (green bar below the green line) were NSS portfolios with smaller capacity sites.

The key insight is that aggregators can meet dispatch conformance targets while simultaneously delivering NSS. However, NSS portfolios with C&I sites could present more risk of dispatch conformance errors. This is because if there is a forecast error for a C&I site, which typically represent a much larger DER capacity than residential sites (often MW versus circa 10kW), the impact on dispatch conformance will be more material compared to smaller capacity sites.

To ensure both the delivery of high firmness NSS and dispatch conformance, aggregators will need to carefully consider the C&I customers acquired for an NSS portfolio – for example, by acquiring sites with a consistent demand profile and sufficient historical data to model.

Additionally, while field tests showed aggregators could meet dispatch conformance targets while simultaneously delivering NSS, the NSS commitment capacity was not clearly identifiable in the aggregators' bids and offers. Rather than bid into the lowest price bands in the bid file to guarantee dispatch, the aggregators bid the NSS capacity requirement into multiple price bands.

In terms of visibility for secure system and market operations, AEMO may not require the granular detail of the quantity committed to NSS within a bi-directional offer but rather, simply require that the total capacity committed by an aggregator portfolio is reflected within its forecasts or bids to AEMO.

AEMO would also need to understand the relationship between the aggregator's portfolio and the distribution network and transmission network interfaces, such as the TNI. In the event VPPs are providing local network services at scale but not yet providing forecasts or bids to AEMO, an appropriate mechanism (and materiality threshold) for AEMO to gain visibility of these coordinated DER commitments would need to be identified.

Two considerations are requiring a forecast of aggregators and AEMO having visibility of DNSP local service delivery activation signals (described above and discussed further in Chapter 6).

Project EDGE NSS tests were scripted events that did not test competitive bidding for local service opportunities. Theoretically, scenarios could arise where wholesale price signals provide a conflicting incentive to an already committed high firmness NSS service. Aggregators would need to develop strategies to manage such conflicts.

In interviews, participating aggregators identified that while a high wholesale price event could give them an incentive to abandon an already contracted local service, the commercial value of a good relationship with the DNSP was deemed important to preserve.

On the infrequent occasions when a local NSS may conflict with a wholesale price signal (e.g. a voltage reduction service coincident with a high wholesale price), the aggregators indicated they would deliver the local NSS with the small subset of their fleet committed to that contract and adjust the remainder of their wholesale portfolios to meet the dispatch target.

INSIGHTS

Optimisation roles and responsibilities

In a future system where DER are integrated into electricity markets, each industry actor would be responsible for a different type of optimisation (covered in more detail in Chapter 8):

- AEMO co-optimises wholesale services dispatch (energy and FCAS).
- DSOs co-optimise network operations to maximise secure hosting capacity (see Chapter 8 for a discussion on the DSO role.
- Aggregators co-optimise services by managing scheduling conflicts among services (e.g. wholesale opportunities conflicting with LSE arming signals) and bidding sufficient quantities at price points that would ensure all their service commitments are dispatched.

5.3.3 Applicability of scheduled resource operating requirements to DER

Current operating requirements for large-scale resources are not fit for DER fleets in the immediate term

The results of field tests conducted during the Project EDGE trial indicate that, with enough time and investment, DER fleets could theoretically meet comparable – but not the same – standards applied to large-scale resources. However, the costs of developing the necessary capabilities may act as a barrier to participation in markets and reduce the value that aggregators can share with customers.

To meet the same standards applied to large-scale resources across the NEM, aggregators would require reliable communications 24/7 in all areas of the NEM – including regional areas.

Aggregators would likely qualify their customers based on the strength and reliability of their communications to ensure compliance with requirements. This could result in consumers in remote areas with less reliable 24/7 communications being unable to participate in VPPs or having less choice.

To meet existing data communications standards, aggregators would also need to connect their control centres to Supervisory Control And Data Acquisition (SCADA) infrastructure, which would not be commercially feasible for VPPs.

A report commissioned by the AEMC estimated that the costs of connecting to SCADA at a basic level would be $0.7-1m, and $2-2.5m for more advanced connections associated with scheduling.[232] See discussion in the section below regarding alternative ways for VPPs to meet appropriate data communications standards.[233]

As discussed in this section, field test analysis identified that DER fleets are not yet able to consistently meet the performance standards applied to large-scale resources. The applicability of current data communications standards to DER fleets is discussed below.

5.3.3.1 Data communications standards

The power system data communications standard (the data communications standard) informs high redundancy and low latency requirements (as well as other requirements) for scheduled resources.[234]

In a high DER future, DNSPs will also require telemetry that complies with the principles of the data communications standard regarding data resilience and latency.

A failure by market participants to meet the requirements set out for providing, maintaining and operating equipment and systems used to transmit and receive power system data and electronic instructions to, and from, AEMO control rooms could result in data accuracy and data latency issues, and potentially response failures. Inadequate equipment and systems that are unable to meet requirements could create gaps leading to power system security and resilience risks.

DER resources are not yet able to meet the same data communications standards as scheduled resources. Accordingly, the future data communications standards relating to DER fleets should be cognisant of both the power system risks that need to be managed and the commercial feasibility for aggregators to implement solutions that comply with these standards.

Field test analysis was focused on the data communications capabilities of the aggregators' own operational meters (telemetry, not smart meters). Figure 88 shows aggregator communications capabilities during the field tests would not meet the current data communications requirements for SCADA.

Figure 88 | Field test results compared to current data communications standards

Current data communications requirements for SCADA

The current Power Systems Data Communications Standard (the data communication standard) focuses on traditional energy markets that have mature communications systems.

Some key end to end time requirements for data transmission to AEMO are outlined below:

Maximum time interval (seconds)

HIGH RESOLUTION DATA:	DISPATCH DATA:	SYSTEM SECURITY PRIMARY DATA:	SYSTEM SECURITY SECONDARY DATA:
2	6	14	22

Project EDGE aggregator communications capabilities

During the field tests, dispatch data took up to 10 seconds for an aggregator to send to their fleet which exceeded dispatch data limits under the current data communications standard.

DISPATCH DATA:
10

The data communications standard was recently reviewed by AEMO following extensive consultation and the final standard was published on 24 November 2022. The updated version took effect on 3 April 2023.

The review resulted in changes in data communications architecture to accommodate direct communications paths to DNSP aggregation systems and clarity of communication paths for different types of participants and equipment. It also allows for AEMO to review and potentially approve certain telemetry with a lesser reliability, considering compliance with required cyber security measures and subject to aggregate limitations in each region.[235]

AEMO considers these changes reflect a necessary and efficient change to accommodate DER and aggregations in a way that addresses both data security and power system security needs in the medium term.

However, the review observes that as the power system continues to evolve, the standard will also need to evolve. The review's final report notes that power system and market changes (such as DER participation) over the next two to three years are expected to result in additional emerging issues for power system data communications, which may require further consideration.[236]

232 GHD Advisory. 2021, Assessment of scheduling costs: Final Report - Australian Energy Market Commission 07 June 2021. https://www.aemc.gov.au/sites/default/files/documents/ghd_report_-_assessment_of_scheduling_costs_-_final.pdf

233 As part of the NEM2025 Program, SCADA Lite is an initiative that aims to reduce entry barriers for smaller generators and demand side resources to provide greater visibility to AEMO and to participate in the market with SCADA that is fit-for-purpose for DER. The scope of the SCADA Lite initiative is under development. This initiative could be considered as a vehicle to progress the development of appropriate requirements for DER data communications.

AEMO. N.d., NEM Reform Program. https://aemo.com.au/en/initiatives/major-programs/nem2025-program),

234 AEMO. 2023, Power System Communication Standard: National Electricity Market. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/AEMO-Standard-for-Power-System-Data-Communications.pdf

235 AEMO. 2022, Review of Power System Data Communication Standard, Final Report and Determination 24 November 2022, p 8. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/review-of-power-system-data-communication-standard/final-stage/data-communication-standard-consultation-final-report_for-publication.pdf?la=en

236 AEMO. 2022, Review of Power System Data Communication Standard, Final Report and Determination 24 November 2022, p 7. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/review-of-power-system-data-communication-standard/final-stage/data-communication-standard-consultation-final-report_for-publication.pdf?la=en

INSIGHTS

Considerations for operational data communication standards

Developing the capabilities to meet current operational data communications standards would be too costly for aggregators in a nascent market. It would likely create entry barriers.

Aggregators noted it could also result in customers in rural areas not being recruited because the cost and compliance risks would be too high.

As such, data communications and analysis requirements should be simplified as much as possible while VPPs are small-scale to avoid unnecessary constraints on their growth.

Additionally, there may be need for a supportive instrument for these requirements outlining how important voice communications from an AEMO control room to an aggregator control room can be supported and maintained.

Discussions with some of the aggregators participating in Project EDGE highlighted some of the challenges to VPPs meeting existing data communications requirements applied to large-scale resources. Specifically, DER reliability and behaviour are different to large-scale resources. Accordingly, the aggregators highlighted that DER are not going to be as predictable in their energy behaviour as traditional large-scale resources because they may be more susceptible to uncontrolled load.

Power system data requirements for the transmission and receipt of power system data and electronic instructions are critical for maintaining system security. Gaps in capabilities and inadequate systems could potentially lead to response failures that compromise secure and reliable operation of the power system.

In addition to reliability risks, there are operational risks AEMO will need to consider if a large number of DER cannot be coordinated through communications requirements. For example, this could lead to more use of emergency backstop measures to curtail PV during minimum system load events.

AEMO should also consider appropriate mitigating actions it will need to take if a large portion of coordinated DER fleet capacity is operated through sub-standard communications.

Cognisant of the challenges aggregators face in meeting existing requirements, and the need for adequate requirements to maintain system security, the stepping-stone approach to participation discussed in section 5.2 may assist aggregators in developing capabilities to meet requirements comparable to those applying to large-scale resources.

One of the aggregators participating in the Project EDGE field trial noted that it supported more rigorous processes around integrating DER. It was of the view that the trial demonstrated VPPs can perform to high standards, although it acknowledged this would require investment and would need to be facilitated by standardisation and a level of simplification where necessary and appropriate. Overall, the aggregator's view was that requirements for coordinated DER would eventually need to be as close as possible to those for large-scale resources.

INSIGHTS

Consideration on developing capabilities to meet requirements and standards

Trade-off decisions (to be clear, not a trade-off to system security) may have to be made regarding the standards and requirements applied to coordinated DER compared to large-scale resources. The development of fit-for-purpose requirements should be cognisant of system risks, as well as the commercial feasibility to implement solutions. Standards could be proportional to the risk and set the baseline for a level of maturity that needs to be developed over time.

A stepping-stone approach could facilitate aggregators developing the relevant capabilities and implementing the necessary solutions to comply with requirements and standards. This approach would enable aggregators to develop capabilities and gradually access revenue opportunities to invest in solutions over time to progress to fully scheduled resources.

Other data communications considerations

The loss of large amounts of scheduling data as a result of public internet failure is a risk that industry will need to manage in the future through compensatory controls. Contingency and default actions for scheduling data loss will need to be developed by industry.

There are key data sets and sharing requirements needed to enable DER market and system integration. Specifically, there are requirements relating to the following functions:

- Forecasting (see section 5.3.2.1)
- Dispatch (see section 5.3.2.4)
- Emergency operations (see sections 5.3.2.6 and 5.3.2.8).

These functions are discussed in the relevant sub-sections, along with the performance of aggregators in the field trial.

Design options need to be identified to minimise the volume of transactions and their payloads to limit the costs and constraints associated with the large-scale volume of data being exchanged in a high DER future. For example, it may be appropriate for some business-to-business or less stringent market services to have different requirements for real-time versus ex-post data requirements, compared to the requirements for bidding and telemetry data for wholesale dispatch.

In Project EDGE, the following measures were implemented to facilitate scalability of DOE data exchange:[237]

- Sending DOEs via a DER data hub, which is more efficient at scale than each DNSP developing its own system
- Sending DOEs periodically instead of real-time, as real-time DOEs would require a more powerful data exchange infrastructure
- Applying the CSIP-AUS data schema, which allowed the 'chunking' of DOE updates to reduce the volume of data transmitted by setting a DOE 'duration' (e.g. three hours) rather than specifying a unique value for every 5-minute dispatch interval.

237 For more detail on the design considerations to enable scalability of DOE data exchange.
Project EDGE. 2022. Project EDGE Public Interim Report Version 1 June 2022. p 17, section 2.3.1. https://aemo.com.au/-/media/files/initiatives/der/2022/public-interim-report.pdf?la=en

5.4 Key insights and implications for industry

Project EDGE field trial results support the hypothesis that a stepping-stone approach to DER integration in wholesale electricity markets would giving aggregators time to progressively develop the capabilities needed for participating in the market as scheduled resources.

This approach would allow aggregators to build market maturity and, in doing so, facilitate aggregators unlocking revenue streams (and therefore enabling business models other than self-consumption-only).

Project EDGE notes the following key insights and implications for industry in adopting a stepping-stone approach.

For policy makers

- Consider how to progress reforms that would facilitate a stepping-stone approach to DER integration that includes at least four stepping-stones:
  1. Facilitating DER access to off-market revenue opportunities to support aggregator capability maturation.
  2. Providing visibility through forecasts of anticipated operation (intention of electricity injection or withdrawal at different price points)
  3. Passive market participation through bids and offers that don't influence the clearing price calculations but allow aggregators that have demonstrated sufficient capabilities to participate as price takers and self-nominate dispatch targets
  4. Graduation to fully scheduled and dispatchable resources.
- Prioritise simple and cost-effective ways for DER to provide minimum levels of aggregated visibility to AEMO and DNSPs. The 'Integrating price-responsive resources into the NEM' (formerly Scheduled Lite) rule change process is considering some approaches that could be prioritised subject to the rule change assessment and consultation process.
- Consider developing robust dispatch conformance and compliance frameworks, noting that the results of the Project EDGE field trial indicate the need for appropriate incentives to comply with market requirements and directions.
- Consider whether regulatory incentives are appropriate for DNSPs to maximise network hosting capacity (demand or generation) during energy market price events.
- When making decisions, consider the following insights from Project EDGE:
- Allow the separate recognition of flexible resources to empower aggregators to develop business models around the DER capacity they can control.
- Project EDGE field trial results showed that aggregators could develop the telemetry capability needed to participate as scheduled resources in the wholesale market. However it has to be financially feasible. Cost-effective and secure alternatives to sharing telemetry data via SCADA connections should be considered to enable VPPs to share telemetry with AEMO, DNSPs and TNSPs efficiently.

For AEMO

- Consider strategies to help industry develop a robust understanding of the requirements of specific markets and services to ensure VPP systems and processes are developed to conform.
- Consider providing simple educational information to support new market entrants accelerate their conformance.
- Develop a detailed roadmap for VPP visibility and dispatchability that includes a self-dispatch model prior to full dispatchability and identifies the largest possible VPP capacity threshold at which full dispatchability is required in future to support development of roadmaps for VPP capabilities and the enabling policy reform.
- Streamline market registration and portfolio management processes for VPPs to enable regular (potentially daily) updates to VPP portfolios.
- Consider easier ways for aggregators to access energy market data before becoming market participants; for example, by updating the NEMWeb portal or developing a more streamlined access to this data.
- Recognise that future data communications standards relating to fleets of DER will need to be cognisant of both the power system risks to be managed and the commercial feasibility for aggregators in implementing solutions that comply with these standards.
- When making decisions, consider the following insights from Project EDGE:
  - Project EDGE field trial results indicate the need for performance testing of aggregators to demonstrate their capabilities to operate under particular market events and with compensatory controls in order to be registered as scheduled resources. Alternatively, other mechanisms would need to be developed or deployed – for example, MSL notices instructing DER generation to turn off or emergency backstop mechanisms
  - Field trial results also indicate the need for appropriate incentives to comply with market directions
  - Field trial results showed fleet size needs to reach materiality thresholds to reduce normalised forecasting error. This should be a consideration when setting the thresholds for VPPs to participate as fully scheduled resources
  - Developing capabilities to meet current operational data communications standards would be too costly for most aggregators in a nascent market. It would likely create barriers to entry. As such, data communications and analysis requirements should be simplified as much as possible while VPPs are small-scale to avoid unnecessary constraints on their growth
  - The development of fit-for-purpose requirements should be cognisant of system risks, as well as the commercial feasibility to implement solutions. Standards should be proportional to the risk and set the baseline for a level of maturity that needs to be developed over time.
- When defining requirements for visibility of DER, AEMO should consider:
  - That not all DER responses will be driven by VPPs, for example by DOEs and B2B services such as NSS and retailer hedging.
  - That data streams from VPPs that provide visibility of price-responsive DER capacity should not dictate the market participation model applied to VPPs (at the NMI or behind the meter)
- A DER data hub can provide efficiencies in gaining visibility across VPP and non-VPP use cases for AEMO and DNSPs.

For DNSPs

- Consider collaboration strategies to develop aligned and consistent conformance monitoring and evaluation approaches across DNSPs to support aggregators develop consistent capabilities for DOE conformance – noting that improved DOE conformance is required in a wide-scale rollout of DOEs so DNSPs can rely on DOEs to manage constraints and avoid the need for network solutions that add more costs to customers.

For aggregators

- When developing business models, consider the opportunities to access potential additional revenue avenues from adopting a stepping-stone approach that moves from a self-consumption model to becoming full scheduled resources. This could include participation in FCAS, RERT and off-market business-to-business services to retailers and DNSPs (such as local network support services). This could facilitate building capability and market maturity and provide certainty of return on investment
- Consider developing business models that provide assurances to customers that net value will be higher from additional trade in VPPs, with the trade-off that the customer may not always be able to self-consume.
- Give priority to developing the capabilities necessary for a robust understanding of the requirements of specific markets and services to ensure systems and process are developed to conform in future and avoid costly retrofits and redesign further down the track.
- When making decisions, consider the following insights from Project EDGE:
  - Project EDGE field trial results showed consistent linear ramping is a key capability challenge aggregators will need to overcome to participate in the dispatch process with material capacity portfolios. In Project EDGE, two of the three active aggregators managed to build some linear ramping capability within a few months. This highlights that capability can be developed progressively and supports the need for a stepping-stone approach to aggregator participation as scheduled resources
  - Field trial results showed fleet size needs to reach materiality thresholds to reduce normalised forecasting error. This should be a consideration for aggregators when developing their business models and considering stepping-stones to developing capabilities toward participation as scheduled resources.
- To co-optimise services, aggregators would need to develop capabilities and strategies to manage scheduling conflicts among services (e.g. wholesale opportunities conflicting with LSE arming signals) and bid sufficient quantities at price points that would ensure all their service commitments are dispatched, as well as operating their portfolios as multiple sub-fleets (e.g. some DER provide a local network support service response and other DER provide a different wholesale market response where a conflict arises).

Table 14: Areas for further research for wholesale market integration

Areas for further research
Zonal aggregation
DOE conformance by VPPs will require operational coordination between DNSPs and AEMO. This could occur through DNSPs providing dynamic information on how much flexible generation or load can be dispatched through a given transmission node. However, such an approach would not fully address the challenges to transmission constraints that VPPs could cause when they reach material scale across a region. When regional VPP concentration in a particular area reaches a high enough level, it may start to impact transmission constraints under certain conditions (for instance, when large amounts of DER are dispatched in response to a high price when the grid is congested in that area). Industry will need to consider an approach to address this challenge. Two possible considerations that require more research are: 1 Each state-wide VPP is split into sub-regional VPPs so that no sub-VPP is operating across transmission constraints. Aggregators would need to submit separate bids and operate them independently. This would add cost and complexity to VPP operations, particularly at large scale in future. The scale threshold at which this approach could apply requires further exploration. 2 VPPs submit regional (state-wide) bids. AEMO then applies a coarse mapping of the bid across resources in the portfolio matched to transmission constraints (using information from the DER Register, Portfolio Management System and mapping to transmission nodes). The systems and processes required – for example, if network mapping from DNSPs is required and whether VPPs would submit a single regional bid – need further consideration. The VPP scale threshold at which a mechanism is needed and the systems, processes, feasibility, implications, roles and responsibilities, and incentives of these two considerations need to be explored and understood.
Performance and communications standards for VPPs
The Project EDGE field trial showed promising results that aggregators can develop capabilities to operate in electricity markets and can value stack to provide multiple services. A stepping-stone approach to gradual participation towards fully scheduled resources can provide aggregators with the opportunity to increase revenue to invest in enhancing their capabilities. However, further research is needed to align the capabilities required to the services provided so as not to impose barriers on a nascent market, while also being cognisant of the power system risk of substandard communications.
DER fleet linear ramping
Linear ramping is important to maintain system security. Two of the active aggregators participating in the field tests were able to develop promising capabilities to linear ramp in a short timeframe. This shows that while developing such capabilities may require time to develop to a standard required for scheduled resources, it is feasible. Further research is needed to identify techniques that could be applied by aggregators to linearly ramp, particularly at scale – the ability to ramp output from a fleet of several hundred DER devices would likely be different to how it might be achieved with thousands or millions of devices.
Management of MSL and DPC-V
Project EDGE undertook several field tests with the objective of demonstrating whether the DOE framework could assist AEMO in managing system security and reliability during MSL and DPC-V events, rather than relying solely on AEMO directions to VPPs. See Table 13 in section 5.3.2.8. AEMO directions could result in generation being partially reduced but some generation may still occur as distributed PV may be servicing uncontrolled or controlled load (depending on the bidding quantity definition). Additionally, only customers participating with an aggregator in a VPP would be activated. Project EDGE found that management of these events through DOEs could result in generation being partially or fully reduced, depending on the DOE allocation point. However, it could also lead to DOE breaches due to uncontrolled or controlled load forecast errors. With the forecast growth of DER, MSL and DPC-V events may become more common, particularly if DER coordination does not eventuate to the extent required. Accordingly, further research is needed to identify appropriate management approaches and mechanisms, including market, B2B and non-market services that could be utilised before the need for an emergency backstop.

EFFICIENT AND SCALABLE DER DATA EXCHANGE

This chapter focuses on the research question:

What is the most efficient and scalable way to exchange DER data between industry actors, considering privacy and cyber security, to benefit all consumers?

Overview

- With potentially more than 100GW of DER connected in the NEM, coordinating DER to maintain ongoing power system requirements and enable value stacking will require large volumes of data to be exchanged between parties in the system. This includes forecasting data, operational data and network limit and constraint data.
- In a high DER future, the way data is exchanged may be different from current mechanisms and different categories of data will need to be shared across many stakeholders. As DER customers and participants increase, data exchange challenges are likely to become exponentially more complex.
- A central hypothesis in Project EDGE is that an industry level DER data hub model provides a more scalable long-term approach for DER data exchange compared with a web of many point-to-point interactions between industry actors.
- Project EDGE tested two different technology approaches for a DER data hub: a centralised approach i which AEMO acts as an operator for the DER data hub and central data broker, and a decentralised approach in which there is no central broker and technology components enable codified partitioning of data to the right participants using digital identities.
- Project EDGE's small-scale field trial of these approaches operated for 333 days, with the data hub facilitating all data exchange between the field trial participants. The project also undertook a theoretical technical and cyber security assessment and a CBA of data exchange approaches, conducted a literature review of international case studies and consulted with industry stakeholders.
- Current problems with data exchange include data inconsistencies between industry participants that create operational inefficiencies; high data exchange costs (which make it uneconomical for market participants to enrol DER in markets and present a barrier to entry for new participants) and limited visibility of DER between industry participants. The absence of widely adopted standards in a decentralising power system may also make it increasingly challenging to maintain cyber security. Without a DER data hub and integrated DER Register, these problems will persist.
- Project EDGE found that a DER data hub approach is more efficient, scalable and aligned to the long-term interests of consumers than a point-to-point approach. In particular, the CBA identified a data hub approach as one of four enablers of the economic benefits generated from a coordinated approach to DER integration within the NEM
- The design of any future DER data hub should consider whether to enable end-to-end connectivity, which would allow DER to connect directly to the DER data hub 'natively' on installation. This would support greater customer choice in being part of a VPP and – when combined with a DER Register – deliver other system security benefits.
- Key insights from the trialling of a DER data hub are:
  - There is broad but tentative industry support for the data hub concept.
  - An industry DER data hub solution must be a streamlined, user-friendly experience.
  - Coordination enables efficiency during market events and this is facilitated by AEMO having visibility of DER through the DER data hub.
- Project EDGE also identified a range of new capabilities related to DER data exchange that are required to support power system security in a high DER NEM These include layered intelligence capabilities, cyber security measures and a consistent approach to DER compensatory controls.
- Project EDGE recommends adoption of a phased implementation approach to develop and implement a NEM-wide DER data hub, involving collaborative planning with industry. Detailed design and technology choices for a DER data hub should not be made until the design principles, policy objectives and potential use cases are agreed among industry.
- Key design principles and policy objectives to be resolved relate to, but are not limited to, ownership, cost recovery, governance, operation, innovation and development, connectivity and use cases.

6.1 Context

Project EDGE has considered this research question in the context of a high DER future, forecast in AEMO's 2022 ISP.[238]

With potentially more than 100GW of DER connected in the NEM, coordinating DER to maintain ongoing power system requirements[239] and enable value stacking (discussed in section 5.3.2.9) will require large volumes of data to be exchanged between parties in the power system, including the following key categories of data:

- **Forecasting data:** to anticipate and predict the performance of resources (for example aggregator portfolio bids and offers)
- **Operational data:** to monitor performance of resources (for example aggregator portfolio telemetry data)
- **Network limit and constraint data:** to ensure resources operate within network capacity limits (for example DOEs). Breaches of these limits can reduce asset lifespans or lead to safety issues
- **Standing data:** to ensure consistent and complete data on key characteristics of DER, which underpins visibility and the ability to coordinate DER.

As the impact of DER volumes become more material on power system dynamics, the coordination of DER will need to support these operational pre-requisites. However, the way data is exchanged may be different. For instance:

- Today, large-scale generators provide operational telemetry by connecting to a dedicated SCADA system (a hardwired connection to the site) with estimated costs between $700,000 for a basic connection and $2.5m for an advanced connection.[240] DER differ from large-scale resources in that they comprise of many distributed, consumer-owned resources. Currently VPPs operate using 3G/4G or customer internet connections. A dedicated SCADA connection to each house is not feasible, nor is there a specific requirement for DER.
  - An alternative approach where VPP level telemetry is transmitted from the VPP operator to AEMO and network service providers via the internet would likely be more cost-effective than connecting to SCADA.
- Transmission Network Services Providers (TNSPs) provide network limit data to AEMO for inclusion in the central dispatch process, but it is not feasible to do this for distribution networks that have thousands more network assets and constraints to manage without significant and prohibitive increases in costs.
  - As discussed in Chapter 4, DNSPs communicating DOEs to DER or their connection points (including those represented by aggregators) is a more efficient way to ensure distribution level power flows remain within network capacity limits.
  - It will also be important for DNSPs to communicate DOEs to AEMO and TNSPs for visibility, so that the level of curtailment expected can be incorporated into operational forecasting and potentially integrated into a real-time validation of VPP bids against the sum of their DOEs (see sections 4.3.5.2 and 8.3.4.2 respectively).

These categories of data will need to be shared across many stakeholders, including aggregators, VPP software providers, Original Equipment Manufacturers (OEMs), retailers, AEMO, DNSPs and TNSPs.

238 AEMO. 2022, 2022 Integrated System Plan, p 9; p 54. https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

239 AEMO. 2020, Power system requirements July 2020. https://aemo.com.au/en/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper

240 GHD Advisory. 2021, Assessment of scheduling costs: Final Report - Australian Energy Market Commission 07 June 2021. https://www.aemc.gov.au/sites/default/files/documents/ghd_report_-_assessment_of_scheduling_costs_-_final.pdf

6.1.1 DER data exchange use cases

Table 15 outlines many DER data exchange use cases that will be required in future, but it is not an exhaustive list. It is likely that additional use cases will emerge that are yet to be conceived.

Table 15: DER Data Exchange use cases

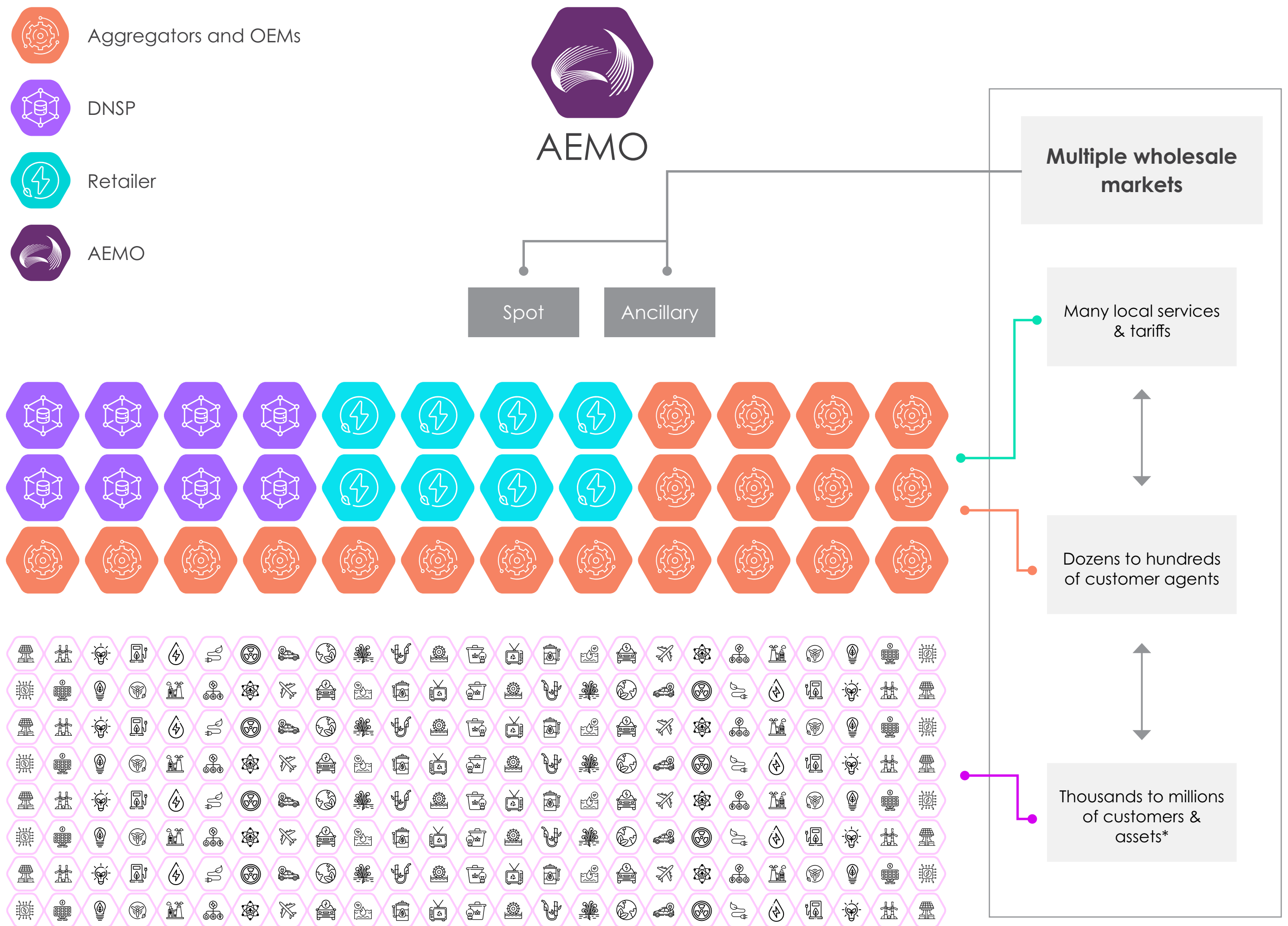
Source: Project EDGE, Data Hub Lessons Learnt Report[241]

Note the diagram uses the term 'zero export limit'. This report uses the term 'dynamic export limit' to communicate that the adjustability of exports drives value for retailers.

241 Project EDGE. 2023, Project EDGE: DER Data Hub Lessons Learnt Report June 2023, p 18. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

Figure 89 illustrates the data exchange challenges that will face a future market as DER customers and participants increase. This growth will make data exchange challenges exponentially more complex than today.

Figure 89: The data exchange challenges for the market in a high DER future



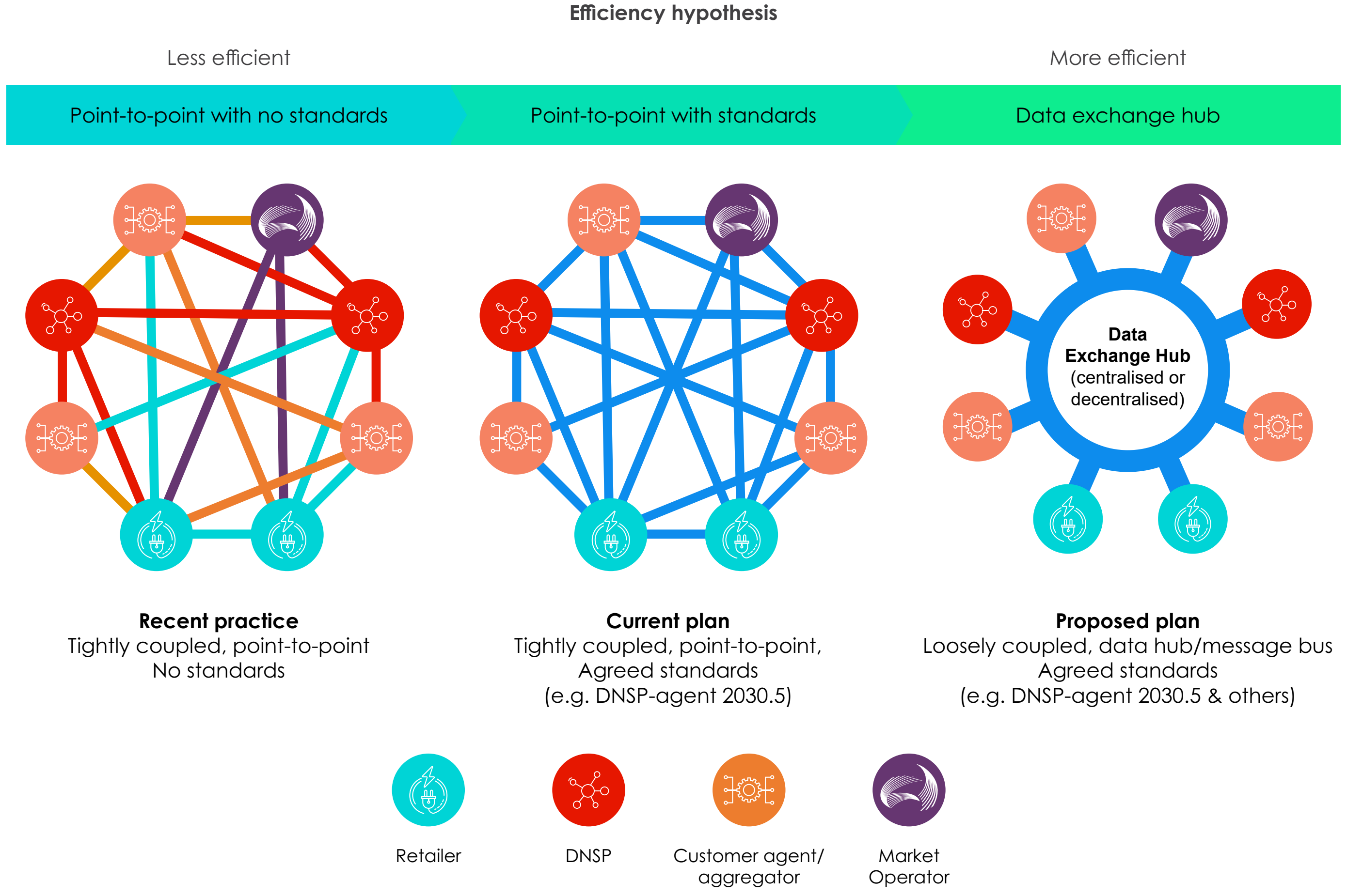
Source: Project EDGE, DER Data Hub Lessons Learnt Report[242]

242 Project EDGE. 2023, Project EDGE: DER Data Hub Lessons Learnt Report June 2023, p 18. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

6.2 Approach

A central hypothesis in Project EDGE is that an industry level DER data hub model provides a more scalable long-term approach for DER data exchange compared with a web of many point-to-point interactions between industry actors.[243]

Figure 90: DER data exchange efficiency hypothesis



Project EDGE has examined two different technology approaches for a DER data hub:

- Centralised approach in which AEMO acts as an operator for the DER data hub and central data broker, receiving / transmitting data in a 'hub and spoke' model, like the current B2B e-Hub[244]
- Decentralised approach in which there is no central broker and technology components enable codified partitioning of data to the right participants using digital identities.
- This decentralised approach may also enable alternative ownership, governance, operating and cost recovery models to the traditional centralised approach., This could decentralise or share responsibility for these elements across permissioned participants with the aim of better facilitating participants to innovate and deliver services to DER customers.

More information on the need for scalable data exchange and the options for scalable DER data exchange can be found in Chapter 4 of the Project EDGE Interim Report.[245]

243 UOM. 2022, Project EDGE Master Research Plan February 2022, p 37. https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en

244 AEMO. 2018, Shared Market Protocol (SMP) Technical Guide: Provides participants with the technical specifications for the delivery of B2B transactions using the E-hub. https://aemo.com.au/-/media/files/electricity/nem/retail_and_metering/b2b/2018/b2b-smp-technical-guide.pdf?la=en&hash=E99BF018F014EC32B792A7D1D55C0D23

245 Project EDGE. 2022, Project EDGE Public Interim Report Version 1 June 2022, Chapter 4. https://aemo.com.au/-/media/files/initiatives/der/2022/public-interim-report.pdf?la=en

Project EDGE has evaluated the data exchange hypothesis in the following ways:

- **A practical, small-scale field trial** of both centralised and decentralised approaches to a DER data hub using a proof-of-concept technology solution
- **A theoretical technical and cyber security assessment** of point-to-point, centralised hub and decentralised hub approaches, conducted independently by EY[246]
- **A cost-benefit analysis** of these data exchange approaches, conducted independently by Deloitte Access Economics[247]
- **Literature review of international cases studies** of data exchange approaches similar in concept to a DER data hub (key cases studies are outlined in section 6.3.1.3)
- **Extensive stakeholder engagement** through interactive sessions in each of the Project EDGE forums[248] on the research question, statement validation, and categorisation, prioritisation and use case validation.

6.2.1 DER data exchange problem statements

The stakeholder engagement process was instrumental in identifying and validating a number of DER data exchange-related problem statements. These problem statements can be summarised into the following four categories:[249]

- **DER data inconsistency across industry participants:** Today, DER standing data – the metadata of DER devices such as equipment type, model, and capability – is replicated across multiple independent systems maintained by AEMO, DNSPs, retailers and customer agents. Data reconciliation processes are limited, and discrepancies inevitably arise over time. These inconsistencies create significant operational challenges and inefficiencies for all stakeholders, as DER standing data represent the foundational inputs for nearly all market B2B transactions.
- **High data exchange costs:** Currently, market participants and non-registered VPPs incur significant costs implementing and maintaining a series of bespoke, bilateral data exchange integrations with DNSPs and AEMO. These costs present barriers to entry for new participants and burdens for existing ones, which can restrict competition and scaling of DER services. Ultimately high data exchange costs diminish the value proposition of DER for consumers by making it uneconomical for market participants to enrol DER in markets and/or offer competitive, innovative plans.
- **Visibility of DER between industry actors:** DER operational data is fragmented across multiple independent IT systems, and it is costly and complicated for industry participants to selectively disclose this data with each other, inhibiting their ability to perform their respective functions in the market.
- **Maintain cyber security in a decentralising power system:** In the absence of widely adopted standards, the inherent variation in proprietary DER platforms and protocols currently used by industry actors makes it challenging to establish uniform, controlled and auditable digital identities and associated data exchange systems that establish trust and implement strong security and reliability capabilities.

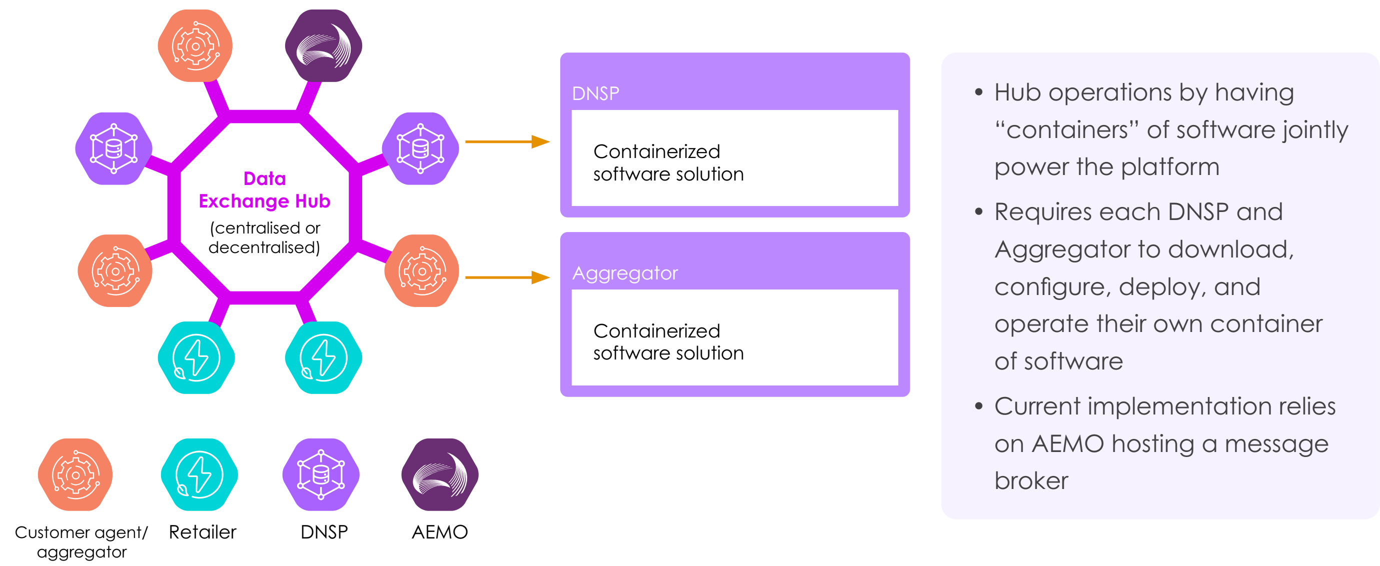
6.2.2 DER data hub practical field trial

The practical field trial operated continuously for 333 days, with the data hub facilitating all data exchange between each of the five field trial participants that allowed them to:

- Send, receive and authenticate messages based on the roles that had been issued to and associated with their self-managed identity
- Exchange diverse datasets, ranging from near-real-time telemetry to bulk file uploads of standing data, in support of multiple DER use cases, including.
  - VPP portfolio registration, identify and access management, submission of bi-directional offers and VPP forecasts, communication of DOEs, communication of dispatch instructions for wholesale services (sent by AEMO) and triggering NSS (sent by AusNet Services), and sharing of VPP portfolio telemetry. Further information can be found in the Project EDGE Data Specifications.[250]
- Communicate via one:one (bilateral), one:many (broadcast) and many:many (multicast) channels through a single integration mechanism with the data hub infrastructure.

The proof-of-concept DER data hub implemented in Project EDGE started centralised and evolved to a decentralised hub operating within a centralised environment (i.e. a single node only for the purposes of the trial) utilising Containers for participant integration, the conceptual architecture for which is shown in the figure below.

Figure 91: Conceptual architecture of EDGE Data Hub with Container-based integration



Source: Project EDGE: DER Data Hub Lessons Learnt Report[251]

The primary technical innovations in EDGE's approach to DER data exchange were related to:

- **Integration:** A standardised integration mechanism with a central infrastructure that enabled participants to exchange multiple data types and formats via a single integration
- **Identity and access management:** Enabling participants to perform authentication and authorisation processes for multiple markets and use cases with a single portable, self-managed digital identity
- **Information integrity:** Combining a shared messaging transport layer with identity-based message authentication through a novel distributed consensus technology[252] to ensure consistency and security in the exchange of information between stakeholders

Section 6.3 discusses key insights and implications from Project EDGE's exploration of data exchange in a high DER future, highlighting considerations for industry. Section 6.4 identifies key insights and implications for industry to consider.

246 EY. 2023, Project EDGE: Technology and Cyber Security Assessment May 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

247 Deloitte Access Economics. 2023, Project EDGE CBA Final Report, https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

248 DER Demonstrations Industry Forum (industry). DER Market Integration Consultative Forum (aggregators and retailers), Network Advisory Group (network and distribution businesses).

Project EDGE. N.d., Project Edge Industry Forums. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-industry-forums

249 Further information can be found in Appendix A of the EY Project EDGE Technology and Cyber Security Assessment.

EY. 2023, Project EDGE: Technology and Cyber Security Assessment May 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

250 Project EDGE. N.d., Project EDGE Data Specification documents. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-technical-specifications

251 Project EDGE. 2023, Project EDGE DER Data Hub Lessons Learnt Report June 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

252 The distributed consensus model relates to the identity-based message authentication and not the actual transmission or storage of data.

6.3 Findings

This section summarises key data exchange findings from Project EDGE. Further details on many of these findings can be found in other reports published by Project EDGE, links to which are provided throughout this section.

6.3.1 Point-to-point DER data exchange is not scalable for a 100GW DER future

A DER data hub approach is more efficient, scalable and beneficial for consumers than a point-to-point approach

Both EY's theoretical technical assessment and Deloitte Access Economics' CBA independently confirmed the hypothesis that a DER data hub approach is more efficient, scalable and aligned to the long-term interests of consumers than a point-to-point approach.

There are many examples of centralised data hubs working effectively, including in the NEM with the B2B e-Hub[253] The practical experience in Project EDGE validated that the proof-of-concept decentralised data hub solution worked, albeit at a small-scale and with many practical lessons learnt. These lessons are outlined in section 6.3.3 and in the Project EDGE Data Exchange DER Data Hub Lessons Learnt report.[254]

6.3.1.1 Independent assessments of data exchange options

Independent technical assessment

EY developed a theoretical assessment framework, outlined in Figure 92, that considered the NEO, Project EDGE data exchange principles and four assessment criteria categories.

Point-to-point data exchange solutions scored lowest in each category (Table 16), indicating they are not suitable at scale. Point-to-point integrations may be manageable for individual use cases at small scale, such as a small number of aggregators integrating with one DNSP to obtain DOEs, but the following factors associated with a high DER future mean point-to-point approaches could lead to inefficient outcomes for consumers:

- Proliferation of aggregators needing to obtain DOEs from all DNSPs across the NEM
- Proliferation of other use cases, such as, but not limited to:
  - Retailers sending dynamic export limits to DER to manage negative price exposure
  - DNSPs sending Dynamic Network Prices to aggregators to incentivise behaviour
  - EV charging operators receiving DOEs or dynamic import limits from DNSPs and retailers respectively in future.
  - A scalable and competititve trade of standardised NSS that enables aggregators to offer and deliver NSS at a lower cost.

Other use cases and problem statements are captured in the appendix of the EY report.[255]

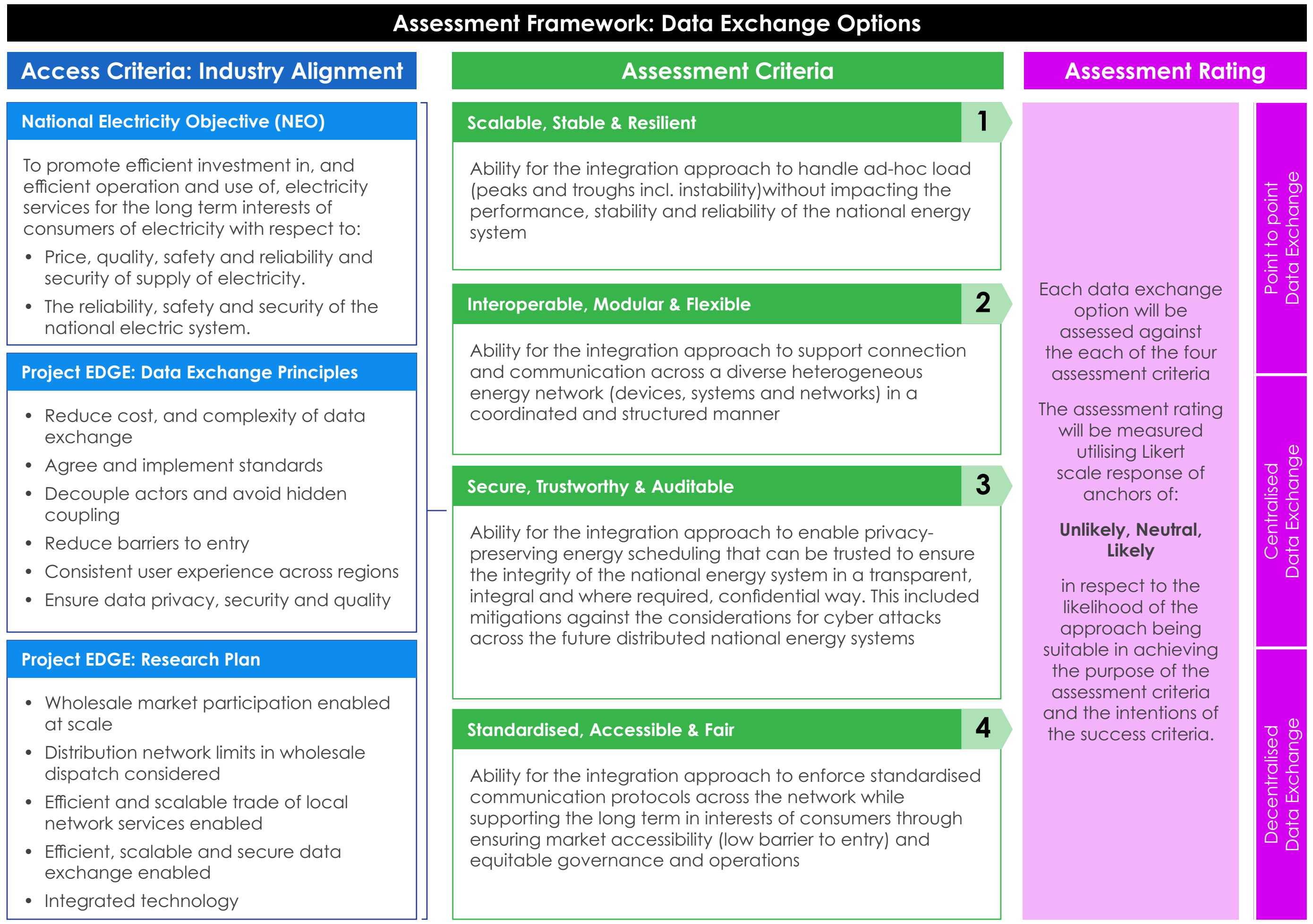
See section 6.3.1.2 for a comparison of the point-to-point and data hub approaches for two use cases (DOEs and retailers sending dynamic export limits).

253 Clause 7.17.1 of the National Electricity Rules prescribes that AEMO must provide and operate a B2B e-Hub, defined as an electronic information exchange platform provided, maintained and operated by AEMO to facilitate B2B communications.

254 Project EDGE. 2023. Project EDGE DER Data Hub Lessons Learnt Report June 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

255 EY. 2023. Project EDGE: Technology and Cyber Security Assessment May 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

Figure 92: EY assessment framework to evaluate data exchange options



Source: EY, Project EDGE Technology and Cyber Security Assessment[256]

Table 16: Scoring outcomes from EY's technical assessment of data exchange options

Point-to-point	Centralised	Decentralised
1 Unlikely	2 Neutral	2.75 Likely

The data hub approaches for DER data exchange scored highest, although scoring between centralised and decentralised approaches was closer.

While DER data exchange involves lower volumes, there is less distinction between centralised and decentralised approaches. However, as DER penetration scales, the theoretical advantages of a decentralised approach could hit a tipping point where they may outweigh the costs and complexities of working out how shared ownership, governance and technology investments would work in practice, noting that industry-grade decentralised data hub technologies suitable for critical energy infrastructure are not currently widely available.

256 EY. 2023. Project EDGE: Technology and Cyber Security Assessment May 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

Independent Cost Benefit Analysis of commercial feasibility

The Deloitte Access Economics CBA, outlined in Chapter 3, strongly supported the commercial case for a DER data hub when compared to a point-to-point approach.

Value was driven by a reduced number of technology integrations required to exchange data between industry actors, provision of a flexible foundation from which to enable the proliferation of DER integration use cases that can evolve as industry use cases develop, and simplification of maintenance, reporting, reconciliation and system updates through standardisation over time. There are minimal cost differences between the centralised and decentralised data hub arrangements.

The CBA found that all consumers would benefit from a coordinated market-based approach to DER integration within the NEM, identifying an incremental benefit of up to $5.15b under the AEMO ISP 2022 step change assumptions and up to $6.04b under the high DER assumptions. The CBA identified a data hub approach as one of the main enablers of these benefits and recommended that industry immediately collaborate on the design and implementation of an industry DER data exchange hub to enable efficient and scalable DER integration (see 3.3.2).

INSIGHTS

Considerations of design principles and policy objectives for a DER data hub

While the CBA and practical and theoretical assessments in Project EDGE support the case for implementing a DER data hub rather than scaling up point-to-point approaches, detailed design and technology choices for a production DER data hub should not be made until the design principles, policy objectives and potential use cases are agreed among industry.

Design principles and policy objectives may relate, but are not limited to the following questions:

- **Ownership and cost recovery:** who should own a DER data hub and how should costs be recovered? Should AEMO own it and recover costs through market fees or should ownership be shared amongst key industry participants with costs recovered through tariffs?
- **Governance:** the current business-to-business e-Hub is governed by the Information Exchange Committee, which is made up of industry stakeholders and chaired by AEMO. Is this an appropriate governance model or should alternative governance models be considered?
- **Operation, innovation and development:** AEMO is currently responsible for operating the e-Hub and implementing development updates to it. An alternative approach may broaden the number of permissioned parties that can develop applications for a DER data hub in order to foster an ecosystem of innovation around the common digital infrastructure.

For example, DNSPs may want to develop applications connected to the DER data hub for digital solutions to procure local NSS or 'flexibility' services at scale from DER aggregators. This could enable DNSPs to operate their own local flexibility markets while supporting standardised DER data exchange. This is explored further in Chapter 8.

Is it appropriate to broaden the number of permissioned parties that can develop applications for a DER data hub (with adequate governance controls) to foster an ecosystem of innovation?

- **Connectivity and use cases:** Project EDGE tested communication between AEMO, AusNet (as DNSP) and three aggregators through a DER data hub. A design choice to consider is whether connectivity should be extended to enable DER to connect natively to the DER data hub as well as industry participants. This is explored further in section 6.3.2 below.

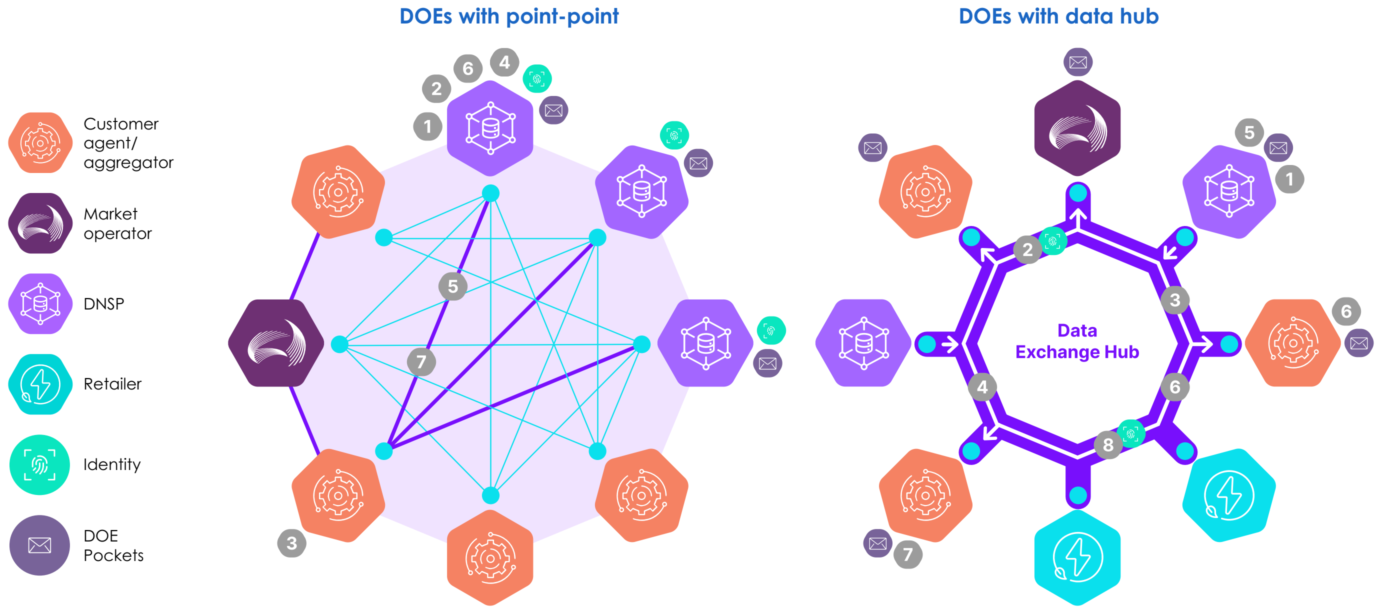
6.3.1.2 Comparison of the point-to-point and DER data hub process for two use cases

This section compares point-to-point with DER data hub approaches for two use cases.

Use case: DOEs

Figure 93 illustrates how the communication of DOEs (as described in Chapter 4) is enabled through a point-to-point approach compared with a data hub approach that was actively field trialled in Project EDGE for 333 days. The steps in the figure are explained in Table 17.

Figure 93: The DOE process with point-to-point architecture (left) and data hub approach (right)



Note: In the point-to-point architecture, all lines represent point-to-point integrations. Purple-coloured lines highlight an example of 1x agent/aggregator integration for the use case shown; however, this integration would need to be replicated for each agent/aggregator: DNSP pair.

Table 17: Communicating DOEs step-by-step explanation

Step	Point to point	DER Data Hub
1	DNSP notified of a site with an aggregator (aka customer agent) that DOEs must be delivered to	DNSP notified of a site with an aggregator (aka customer agent) that DOEs must be delivered to
2	The aggregator then undertakes an organisation identity and portfolio registration process with each DNSP Note: The Identity verification process may not be standardised across parties. Several identities can exist for one aggregator, and be managed by different parties. The verification process may be in addition to the existing identity held with AEMO for market participation	The aggregator then undertakes a streamlined organisation identity and portfolio registration process with each DNSP leveraging the aggregator's pre-validated identity Note: The established identity is managed by one party (e.g. AEMO) and then utilised by other parties. This reduces duplicating processes and thereby enhances market trust

Step	Point to point	DER Data Hub
3	Single integration established between aggregator and DNSP Note: For the aggregator, integration is required per DNSP connection and this may not be standardised	Integration established between DNSP and DER Data Hub Note: Any existing Hub integration may be leveraged throughout all use cases
4	DNSPs map NMIs to aggregator portfolios and send a packet of DOEs per aggregator Note: DNSPs have a constant remapping process and must send multiple DOE packets	Integration established between the aggregator, DER Data Hub and therefore all connected DNSPs
5	Aggregator receives and operates within DOEs	DNSPs add new NMIs to batch of DOEs and send one packet of DOEs to the hub
6	The aggregator updates their portfolio information as sites and DER change with each party. Note: The aggregator makes DER portfolio updates with each counterparty (AEMO and DNSPs). This process may not be standardised	The Hub broker takes the single DOE packet based on aggregator portfolio information and sends the correct DOEs to their site aggregator. DOEs could be simultaneously delivered to AEMO for operational visibility
7	DNSP re-maps NMIs to portfolio updates and send a packet of DOEs per aggregator	Aggregator receives and operates within DOEs
8		Aggregator updates their portfolio information as sites and DER changes with AEMO. Note: The Hub maintains participants and portfolio mapping to facilitate B2B interactions
9		This process repeats with any updates to an aggregator's Portfolio. Note: DNSPs can always send one DOE packet without maintaining and managing frequent aggregator portfolio updates

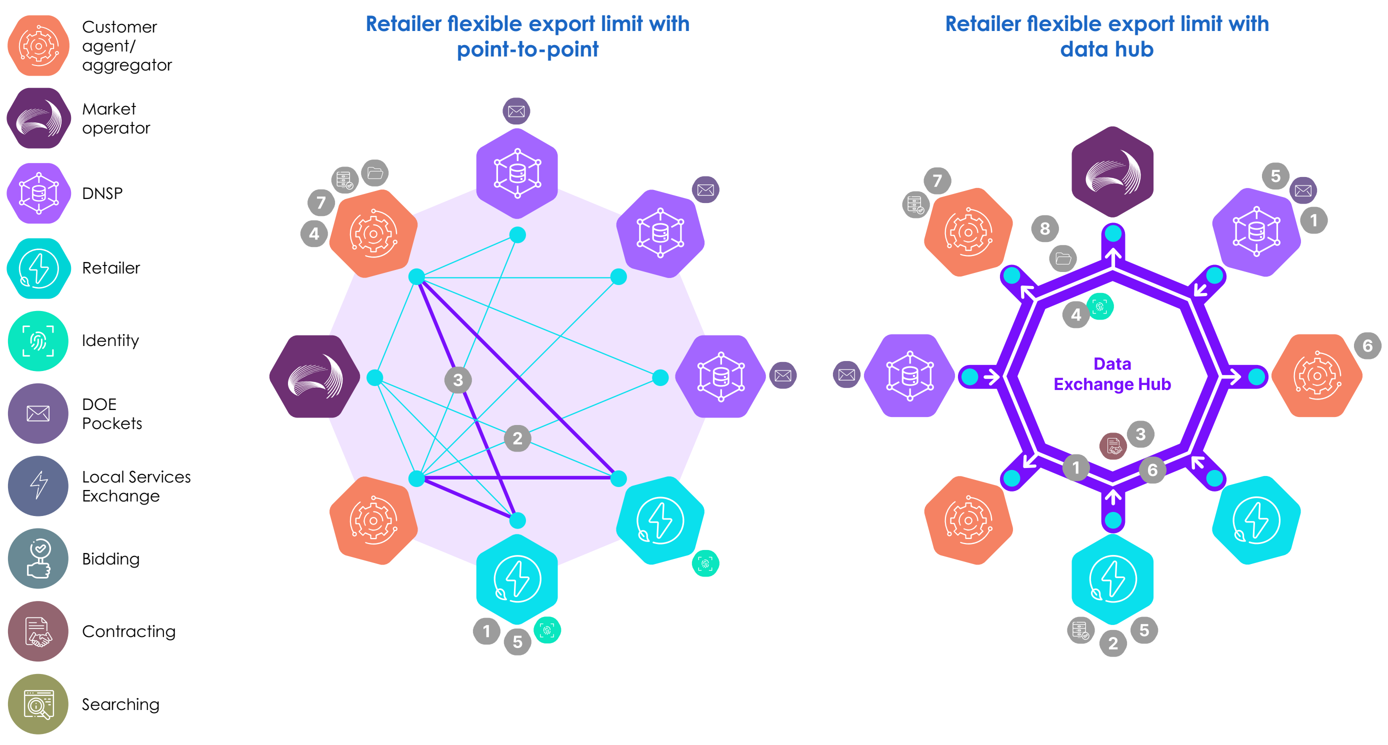
Source: Project EDGE: DER Data Hub Lessons Learnt Report[257]

Use case: retailers sending dynamic export limits

A use case related to the problem of high data exchange costs and confirmed by stakeholders during Project EDGE's round of consultations relates to a retailer's need to issue a 'dynamic export limit' to aggregators during times of negative pool pricing.[258] In the event of extreme negative prices, a retailer may want generation to be turned off and load turned up. The data exchange component of this use case was tested in the EDGE field trial but not the end-to-end service delivery. Figure 94 illustrates how the data exchange for the use case for retailers sending dynamic export limits is enabled through a point-to-point approach compared with a data hub approach. The steps in the figure are explained in the table below.

257 Project EDGE. 2023, Project EDGE DER Data Hub Lessons Learnt Report June 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

Figure 94: Retailer sending dynamic export limit process with point-to-point architecture (left) and data hub approach (right)



Note: In the point-to-point architecture, all lines represent point-to-point integrations. Purple-coloured lines highlight an example of 1x agent/aggregator integration for the use case shown; however, this integration would need to be replicated for each agent/aggregator: DNSP pair.

Table 18: Comparison of point-to-point and DER Data Hub

Step	Point to point	DER Data Hub
1	Customer agent / aggregator or OEM is approached by a retailer to curtail solar generation using a dynamic export limit (DEL) at some of their sites during negative spot prices	Integration established between retailer and DER Data Hub Note: Any existing Hub integration can be leveraged in this use case, including the existing retailer identity managed by AEMO
2	Single integration established between aggregator and retailer Note: The Identity verification process may not be standardised across actors. Several identities can exist for one aggregator, and be managed by different parties. The verification process may be in addition to the existing identity held with AEMO for market participation	Retailer establishes DEL channel(s) to signal DEL needs
3	Retailers map NMIs to portfolios and send a DEL request per aggregator	Retailer uses broadcast messenger function to notify registered aggregators on the hub and facilitate connection Note: The established identity is managed by one party (e.g. AEMO) and then utilised by other parties.

258 Project EDGE. 2023, Project EDGE DER Data Hub Lessons Learnt Report June 2023, p 38. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

Step	Point to point	DER Data Hub
		This reduces duplicating processes and thereby enhances market trust
4	Aggregator receives and executes DEL	Aggregator's existing integration to the hub used to apply to subscribe to retailer DEL channel(s) Note: Configuration of data hub messenger channels is easier than integrating with other organisations
5	Retailer re-maps NMIs based on aggregator portfolio updates ready to send new DEL request per aggregator. Note: Retailers have a constant remapping process and must send multiple DEL requests per event	Retailer approves access to their DEL channel based on aggregator credentials Note: The retailer controls how the DELs are distributed. The mapping of NMIs by a retailer may exist in the retailer's system or this could be leveraged by a portfolio management system linked to the Hub in the future. The Hub maintains participants and portfolio mapping to facilitate B2B interactions
6	The retailer repeats this process with any updates to the aggregator's portfolio Note: Aggregator makes DER portfolio updates with each counterparty, this process may not be standardised	Retailer sends DEL request to channel
7	Service verification obtained through smart meter data or file transfer	Aggregator receives request and actions DEL at their sites
8		Service verification obtained through smart meter data or file upload via data hub

6.3.1.3 Literature review case studies

The key findings from the literature review on this topic are that:

- Energy data exchange hubs are used extensively around the world to faciliate retail, metering or market data exchange; for example, the existing e-Hub[260] that AEMO operates in the NEM or various data hubs established across Europe to enable efficient sharing of customer meter data.
- Australia is not alone in considering the case for new types of energy-related data exchange hubs. For instance:[261]
  - The UK is exploring a 'digital spine' concept for the energy system (see the case study below)
  - Common infrastructure for distributed flexibility services is also explored in two case studies in Chapter 7 section 7.3.1 in the UK and Norway.

259 Project EDGE. 2023, Project EDGE DER Data Hub Lessons Learnt Report June 2023, p 38. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

260 AEMO. N.d., Factsheet: B2B E-Hub. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Power-of-Choice/FAQ/PoC-Fact-Sheet-5---B2B-e-Hub.pdf

261 Siöstedt S and Wang-Hansen M. 2021, EU-SysFlex: Market and Governance of Existing Data Access & Exchange Platforms – Sub-task 5.1.3. https://eu-sysflex.com/wp-content/uploads/2021/03/EUSYSFLEX-5.1.3-Report-Data-Platforms-FINAL-1.pdf

CASE STUDY

UK Energy Digitalisation: digital spine

The concepts being explored in Project EDGE are very similar to recommendations from a UK Energy Digitalisation Taskforce to develop a digital spine for the energy system "to enable plug and play options, encouraging whole system interoperability and standardised data sharing"[262] – although Project EDGE is focused on DER-related data exchange.

The UK Government, Ofgem and Innovate UK are initiating a joint respons[263] to the energy digitalisation recommendations that includes commissioning a feasibility study on the digital spine concept.

The Request for Tender document for the digital spine feasibility study states that:

"A digital net zero energy system, built on principles of data openness, sector-wide interoperability and security by design, can help to create an efficient whole-system approach to sharing data. Everyone can benefit from the digitalised exchange of data, with improved knowledge, insights and analysis driving improvements in energy products, services, entrepreneurial opportunities and policy-making."[264]

The Energy Digitalisation Taskforce report describes 'a digital spine' as:

"a thin layer of interaction and interoperability across all players which enables a minimal layer of operation critical data to be ingested, standardised and shared in near real time".[265]

The Energy Digitalisation Taskforce also recommends the establishment of the following elements that are complementary to the digital spine concept:

- Energy Asset Register and Energy Data Catalogue
- Data sharing 'fabric' - governance, administrative and consistent technology solutions to share data across organisations
- Network Data standards and Flexible Asset standards.

In its Call for Input on the Future of Distributed Flexibility, Ofgem describes the current challenges it is seeking to solve.

"Ofgem has seen (DER) participation in energy markets struggle, with challenges around market access and coordination. High transaction costs, barriers to market entry, the limited value of individual services, limited access to information, and a lack of coordination persist."[266]

"We do not think a consistent, low-friction environment for decentralised flexibility will emerge either organically or in time."[267]

Ofgem has received responses[268] to a call for input on the future of distributed flexibility, with:

- 93% (of 90) respondents agreeing there is a strong case for change to address market failures and to support distributed flexibility at scale
- Most respondents supportive of creating a common digital energy infrastructure, with 63% supporting some form of the medium archetype (this was the approach trialled by Project EDGE)
- Near universal consensus that being unable to stack revenues across multiple flexibility markets would be a significant barrier to entry and impede the commercial uptake of DER.

These challenges and concepts are all explored in Project EDGE, and it is envisaged that a future DER data hub would include an upgraded DER Register, as well as data standards and appropriate governance arrangements to support its establishment and ongoing development.

262 Catapult Energy Systems. N.d., Energy Digitalisation Taskforce publishes recommendations for a digitalised Net Zero energy system. https://es.catapult.org.uk/news/energy-digitalisation-taskforce-publishes-recommendations-for-a-digitalised-net-zero-energy-system/

263 UK Government Department of Business, Energy and Industrial Strategy. 2022, Energy Digitalisation Taskforce report: joint response by BEIS, Ofgem and Innovate UK. https://www.gov.uk/government/publications/digitalising-our-energy-system-for-net-zero-strategy-and-action-plan/energy-digitalisation-taskforce-report-joint-response-by-beis-ofgem-and-innovate-uk

264 UK Government Department of Business, Energy and Industrial Strategy. 2022, Flexibility Innovation Programme: Energy System 'digital spine' feasibility study. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1109954/energy_system_digital_spine_scoping_study.pdf

265 Catapult Energy Systems. N.d., Energy Digitalisation Taskforce publishes recommendations for a digitalised Net Zero energy system. https://es.catapult.org.uk/news/energy-digitalisation-taskforce-publishes-recommendations-for-a-digitalised-net-zero-energy-system/

266 Ofgem. 2023, The Future of Distributed Flexibility: Call for input, p.11. https://www.ofgem.gov.uk/sites/default/files/2023-03/Ofgem%20Call%20for%20Input%20on%20the%20Future%20of%20Distributed%20Flexibility2023.pdf

267 Ofgem. 2023, The Future of Distributed Flexibility: Call for input, p.31. https://www.ofgem.gov.uk/sites/default/files/2023-03/Ofgem%20Call%20for%20Input%20on%20the%20Future%20of%20Distributed%20Flexibility2023.pdf

268 Ofgem. 2023, Response letter to Ofgem's Call for Input on the Future of Distributed Flexibility. https://www.ofgem.gov.uk/sites/default/files/2023-07/Distributed%20Flex%20CFI%20Response%20Letter.pdf

CASE STUDY 1

EDA Data Exchange Platform (Austria) An example of an operational decentralised data exchange platform is outlined below relating to EDA, which is owned by 15 system operators and based in Austria.[269]

Figure 95: EDA model

Company Overview:

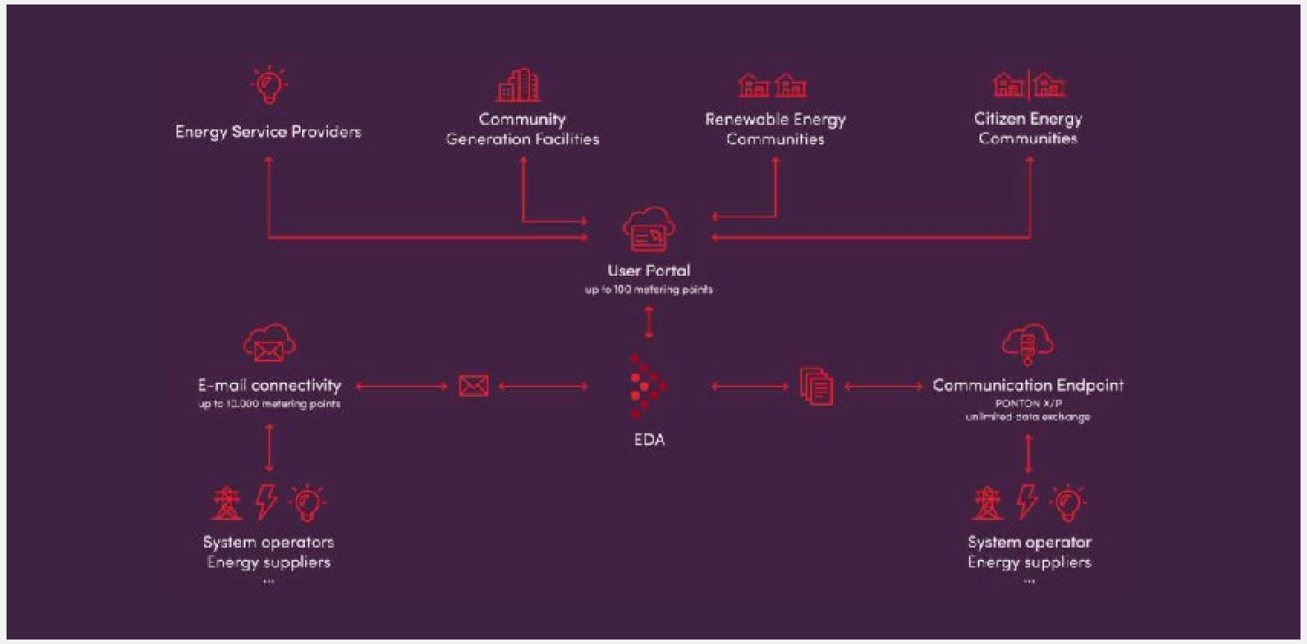
- EDA was established in 2012 and is owned by 15 Distribution System Operators in Austria.
- The founding concept of EDA was to create a uniform, decentralised, electronic data exchange for the Austrian electricity and gas sector.
- EDA is an independent and open information and service platform, enabling all market participants free access to the energy market, secure and efficient communication and standardised information exchange.
- Ponton GmbH is the ongoing technology partner for EDA.

Product Overview:

- The secure, standardised and simple energy data exchange is based on the following principles: standardised communication protocols, standardised data formats, standardised business processes.
- Data sovereignty is decentralised in the participants in the EDA infrastructure – data is transported via the EDA infrastructure but not stored there and cannot be read out. The data is thus only stored at the individual authorised participants. This fact minimises data, and there is no single point of failure.
- Decentralisation also ensures privacy by design and security by design, in accordance with the General Data Protection Regulation

NEM Opportunity:

- The EDA model shows that a decentralised approach to a data exchange can work in an industry-wide deployment.
- It is possible for a decentralised approach to DER data exchange to achieve shared ownership across permissioned industry participants, a unified and standardised infrastructure supporting secure end-to-end communication, decentralised data sovereignty, and privacy/security by design.
- This deployment provides a detailed blueprint for how a decentralised data exchange platform can be established in practice.



269 Energy wirtschaflicher datenausfausch (EDA). 2023, EDA. https://www.eda.at/ueber-uns

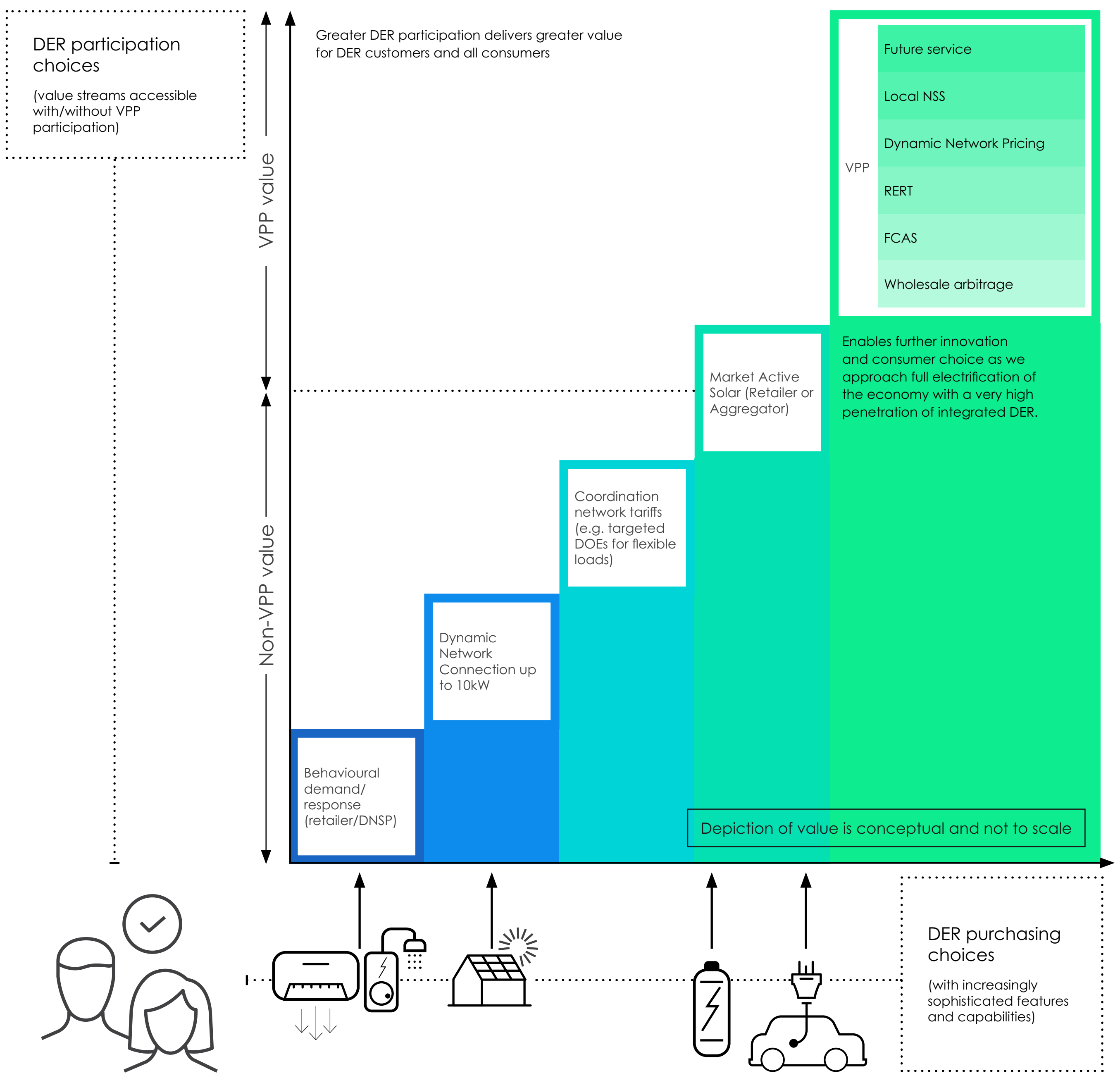
This case study provides an existing example of shared ownership, governance and decentralised data sovereignty that could inform the design of a DER data hub in the NEM if shared approaches were agreed as a policy objective.

6.3.2 End-to-end connectivity may deliver further consumer benefits

The design of a DER data hub implementation should consider whether to enable end-to-end connectivity

Although Project EDGE tested data exchange between industry actors (aggregators, DNSPs and AEMO), end-to-end connectivity would enable DER to connect to a DER data hub 'natively' on installation. Enabling DER to natively connect to a DER data hub would support customer choice as customers would be able to participate in the use cases/programs outlined above (and illustrated in Figure 96) whether they choose to be part of a VPP or not. Choosing to participate in a VPP should enable further opportunities to obtain value from their DER.

Figure 96: Customer choices for various levels of DER participation



End-to-end connectivity and combining the DER data hub concept with an updated DER Register could also enable a range of further benefits. The register could support dynamic updates to data: for instance, each device could have a digital identity that supports changes to the register over time as settings are updated or as the device joins a VPP portfolio, rather than just capturing standing data on installation. The following potential benefits were identified during stakeholder engagement:

- **Secure integration with the DER ecosystem:** Devices and entities with a digital identity could automatically upload their standing data, settings and credentials to an updated DER Register as they first connect to the internet (in a 'plug and play' installation experience), saving time, effort and errors in manually uploading data using current processes.
- **DOEs for all new connections:** All new PV connections, even when not signed up to an aggregator, could receive DOEs from DNSPs via the DER data hub. This would remove costs from the industry as it would enable DNSPs and retailers to send export limits to PV directly. This could also accelerate customer coverage of DOEs, a key DER value driver, as recommended in the CBA (see section 3.1) and provide AEMO the required visibility at the same time.
- **Privacy by design:** Data access and permissions for different parties can be codified at a granular level so that sensitive data is not exposed.
- **VPP portfolio management:** DER device identities could be attached to registered VPP operators, and even to multiple VPP portfolios for services that the device supports: for instance, wholesale energy and local NSS. VPPs, DNSPs and AEMO could utilise this data as a single source of truth for VPP portfolio management, which could also support the customer switching process.
- **End-to-end visibility and auditability across the DER ecosystem:** Digital identities and Verifiable Credentials (VCs) at each level of the supply chain (for example, device and aggregator and retailer level) enables greater integrity checking and isolation of operation via revocation of VCs if a security threat is identified. Automatic registration of DER on their connection to the internet could improve DER standing data quality and thereby visibility for AEMO and DNSP operations (see section 5.1.2.2).
- **Secure interoperability across the DER ecosystem:** An extended capability of digital identities and VCs may enable any retailer and aggregator to send control signals to compatible devices if they have correct VCs, customer consent and are connected to a DER data hub. This would give customers freedom to switch between providers and enable aggregators to easily coordinate numerous different device types within their portfolio.
- **Compliance with industry standards:** The DER data hub may enable traceability of DER settings and firmware upgrades to monitor compliance to standards (for example, AS 4777.2.2020 or CSIP-AUS[270]).

Without a DER data hub and integrated DER Register, the status quo remains and the problem statements identified in section 6.2.1 will persist.

CASE STUDY

Three models for delivering DER control signals

SA Power Networks has proposed the potential to natively connect DER. To support their flexible exports program,[271] market active solar trial[272] and diversify tariff trial[273] SAPN has developed three ways to connect to their systems.

These use cases are potential concepts that are being trialled and adopting them beyond a trial environment may encounter regulatory challenges with the ring-fencing framework. If these challenges can be overcome, and the trial demonstrates realisable benefits, a DER data hub would be able to facilitate these use cases in an interoperable manner.

The figure below summarises the use cases as:

- **Native model**, in which DER devices connect directly to SAPN's systems
- **Gateway model**, in which a hardware 'gateway' device, typically operated by a third-party aggregator/service provider on behalf of the customer, is an intermediary between SAPN's systems and the DER device (e.g. SwitchdIn droplet or Reposit box)
- **Cloud model**, in which a third-party aggregator/service provider acts as an intermediary between SAPN's systems and the cloud operational systems for the DER device.

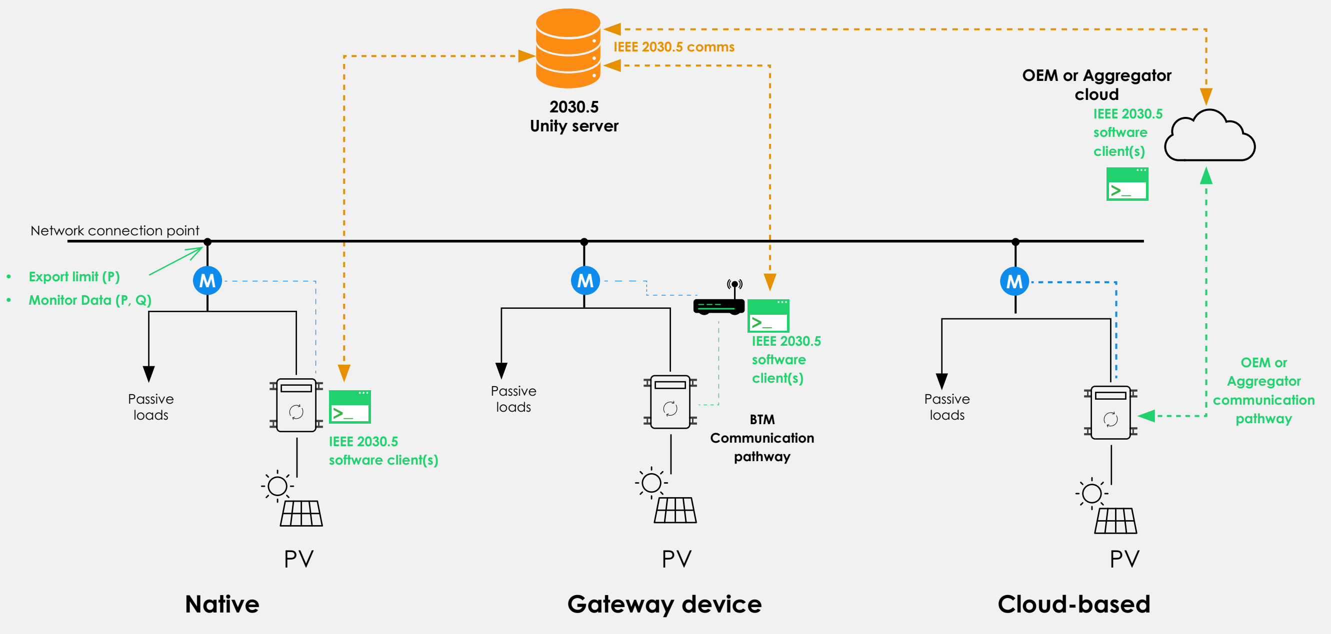
270 The Standards Australia handbook of CSIP-AUS (more formally known as SA HB 218:2023) has been published, and is available for free on the Standards Australia store website. Standards Australia. 2023, SA HB 218:2023: Common Smart Inverter Profile – Australia with Test Procedures. https://store.standards.org.au/product/sa-hb-218-2023

271 SA Power Networks. N.d., Flexible Exports – A new solar connection option that gives you more. https://www.sapowernetworks.com.au/future-energy/solar/

272 SA Power Networks. N.d. Market Active Solar Trial. https://www.sapowernetworks.com.au/future-energy/projects-and-trials/market-active-solar-trial/

273 SA Power Networks. N.d., Tariff Trials 2023-24. https://www.sapowernetworks.com.au/public/download.jsp?id=320663#:~:text=The%20trial%20tariff%20Electrify%20provides,%3A00am%20%E2%80%93%204%3A00pm.

Figure 97: Initial proposal of DOE interface landscape[274]



These systems support a range of use cases for each project in the SAPN trials:

- **Flexible exports:** SAPN communicates DOEs either directly to DER devices or via third-party service providers that adhere to the DOEs on behalf of customers.
- **Market active solar:** Retailers (for example Simply Energy and AGL in this trial) develop new retail offers that reward customers for enabling their solar to be responsive to wholesale energy market pricing, reducing the retailers' exposure to negative wholesale prices. Retailers can implement this by utilising SAPN's capabilities to send a retailer requested flexible export limit to their customers' DER when wholesale prices are below a negative price threshold. Adopting this beyond a trial may encounter ring-fencing challenges that would need to be addressed.
- **Diversity tariff:** This type of coordination tariff targets EV owners by offering a daily rebate ($0.33) to allow SAPN to regulate the charging rate of their smart EV chargers when the distribution network has limited capacity. This is implemented by communicating a targeted DOE directly to the EV charger using the Open Charge Point Protocol (in the trial), but it could also be sent via a third-party service provider in the future.

274 DEIP. 2022. Dynamic Operating Envelopes Working Group: Outcomes paper – March 2022. https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

6.3.3 Practical lessons learnt

Lessons learned from the Project EDGE field trial provide key insights for industry to consider

Developing and operating a novel, proof-of-concept DER data hub for almost a year has uncovered many practical lessons learnt that are outlined in detail in the Project EDGE DER Data Hub Lessons Learnt report.[275] This section highlights some of the key insights that can be taken forward in a technology agnostic way to any future DER data hub should industry choose this path.

There is broad but tentative support for the data hub concept

Feedback from Project EDGE participants and industry stakeholders engaged through the various forums (such as the Demonstrations Insights Forum, DER Market Integration Consultative Forum and the Networks Advisory Forum)[276] indicated there is broad but cautious industry support for implementing a DER data hub concept, noting that further work is required to determine the optimal design to ensure that a DER data hub delivers simplified user experiences rather than adding further complexity to the industry. Some sample quotes from different aggregators include:

- On the DER data hub concept: *"One of the big challenges in accessing and monetising DER flexibility is the complexity and cost of interconnectivity. The more it costs, the less there is to share with customers. A DER data hub could significantly reduce this cost and complexity, particularly in light of the industry's progression towards dynamic export limits."*
- On the challenge of engaging in multiple identity verification processes: *"If you are used to the mess that multiple MS accounts causes, you would understand why a centralised login and access point, with reliable verification and ease of access is a mandatory industry need."*
- On the need for standardisation: *"DoE's do not seem like they will be the biggest issue assuming networks leverage the work of SAPN to implement CSIP-AUS. Integrating across multiple proprietary platforms for network services could become cumbersome."*

An industry DER data hub solution must offer the flexibility of multiple integration mechanisms while maintaining standardisation

Project participants indicated support for the data hub solution architecture, but the experiences of several project participants indicate that the trialled Container-based integration method is likely to be considered too complicated for widespread adoption and did not offer sufficient flexibility.

An industry DER data hub would need a more streamlined, user-friendly experience that is ideally consistent with other ways that industry participants exchange data with each other via a common technical standard. For example, enterprise cloud services that offer cloud-native applications in a simple user interface and automated back-end deployment processes, a standalone platform (web or desktop application) and Application Programming Interfaces (APIs).[277] Developing integration methods that provide maximum flexibility for participants mitigates the need for specialised IT skills or resources to establish and maintain integration.

Coordination enables efficiency during market events

With the NEM market suspension occurring in June 2022, Project EDGE established a test plan to learn from this exceedingly rare event.[278] Multiple tests were conducted to help elucidate the required considerations for AEMO directing a high DER NEM where a substantial proportion of supply and demand is managed via aggregator Virtual Power Plants (VPPs):

- When formulating directions to VPPs, coordination is required between AEMO and DNSPs to ensure that dispatch targets are able to be achieved within the DOEs provided by the network.
- Such coordination was facilitated in the trial through capabilities such as AEMO having visibility of DER through the DOEs published into the DER data hub.
- Given the nature of market operations during such

275 Project EDGE. 2023. Project EDGE: DER Data Hub Lessons Learnt Report June 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

276 Project EDGE. N.d., Project Edge Industry Forums. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-industry-forums

277 Project EDGE. 2023. Project EDGE: DER Data Hub Lessons Learnt Report June 2023. p 65 https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

278 See p.42, point 2 for more details on the tests conducted.
Project EDGE. 2022 Project EDGE, Lesson Learnt Report #2 November 2022. https://aemo.com.au/-/media/files/initiatives/der/2022/project-edge-lessons-learnt-2--final.pdf?la=en

an event, the efficiency enabled by coordinating directions with DNSPs via a data hub, compared to multiple point to point integrations, is significant, especially considering the anticipated large number of VPPs likely to be operating in a high DER future.

A significant capability uplift of the e-Hub would be required to facilitate additional DER use cases

In early engagements for Project EDGE some stakeholders asked how the DER data hub supports capabilities / use cases that are not supported in the e-Hub. The solution developed in Project EDGE features some enhancements relative to the current capabilities of the e-Hub, but also lacks certain capabilities that exist in e-Hub. These are summarised in Table 19 below.

The summary is provided to highlight the significant capability uplift of the e-Hub that would be required to facilitate the DER use cases contemplated in Project EDGE, and their flexibility and operational timescale requirements. Details of the Project EDGE DER data hub solution are included for information purposes only and do not endorse or further prescribe the use of the technology described. The Project Participants do not endorse or intend to prescribe any technology choices or vendors based on this report. The lessons should be assessed for relevance and applied in a technology agnostic manner to any future DER data hub.

Table 19: Attribute and functionality comparison between the e-Hub and the DER data hub solution tested developed in Project EDGE

Attributes and functionalities	Description
Common to the EDGE data hub and e-Hub	• For information sharing between participants and AEMO, both solutions provide similar functionality and implement common security patterns (certificates, ports, payload integrity) • From an identity and access management perspective, both solutions have similar approaches to authenticating participants and authorising specific transactions / permissions via role-based access control • Both solutions support APIs, File Transfer, Schema Validation and Response message formats

EDGE data hub enhancements to the current e-Hub capabilities	• Messages can be sent between participants and DNSPs without configuration by or the involvement of AEMO –a central broker administrator is not required. The data hub solution also supports broadcast patterns to multiple subscribers, such as distributing forecast prices from AEMO to all aggregators. Further, the project's architecture creates an opportunity for participants and DNSPs (or another third party) to host their own transport layer, supporting enterprise resilience as well as independence
	• The general-purpose, open-access messaging infrastructure makes the data hub highly adaptable to new use cases and requirements. For example, it has the ability to enable B2B/B2C schemas and transactions quickly, as well as the ability to use Portfolio Management data to partition and inform select / required recipients as required
	• The complexity of the e-Hub integration and some functionalities are removed, and become a part of the Container. For example:
	  • Enables API, File transfer, and Message Queue (all in one) capability
	  • Validates schema prior to it being sent
	  • Caching of incoming payload

EDGE data hub enhancements to the current e-Hub capabilities	• Integration efficiency is enhanced with:
	  • A single endpoint to connect to industry integration, so that it requires only one firewall port to be opened
	  • A single credential to talk to multiple parties (regardless of which party hosts the Transport Layer)
	  • A single port whitelisted to enable communications (to each Transport Layer)
	  • Security requirements met with a single MTLS certificate (per Transport Layer)
	  • AEMO is not responsible for administering identities or certificates for external organisations – public / private certificates are self-managed by participants and DNSPs
	  • Certificates are tied to an identity/role, and a role has visibility for only those channels/topics to which it has permission (i.e. not every channel/topic is visible to everyone)
	  • Large messages (payloads) are broken up by the Container for transport (and reconstructed)
	  • Each payload is encrypted/decrypted by a one-time use key, enhancing security
	  • The data hub solution supports publish / subscribe patterns (the current e-Hub implementation requires configuration changes for this)
	  • Participants can self-service for child certificates (for development and test purposes)
	  • Deploying Containers with a Kubernetes service have horizontal scalability (with Pods being spun up on demand)
	  • Multiple Containers can be setup in an organisation to cater for different environments (development, test, staging)
	  • Containers (if required) can be set up on a user's machine for development purposes
	  • The EDGE solution can facilitate event-based transactions being 'passed through' – AEMO isn't required to partition (sort) messages / data for the 'correct' recipient

e-Hub capabilities not implemented in Project EDGE	• Synchronous transactions capability
	  • Schema version (n-1) compatibility
	  • Improvements required in logging, alerting and monitoring
	  • Store Messages that are passed between participants (if a requirement)
	  • Store and forward capability (between Initiator and Recipient)
	  • Stop file mechanism (if a requirement)

Design considerations for DNSPs include appropriate compensatory controls

A design consideration in the case for an industry DER data hub relates to DNSPs' responsibility for maintaining customer supply and potential consequences in the event of supply issues.

If DNSPs operate their own systems to publish DOEs, and those systems suffer a failure that leads to power quality issues for customers' supply, then DNSPs have full control of those systems and can manage that risk accordingly.

However, if DNSPs publish DOEs via an industry data hub, and customers face supply issues as a result of a failure of third-party systems, without appropriate compensatory controls DNSPs may still face consequences for systems failures outside of their control.

Although an industry DER data hub would be designed to be highly available, with effective redundancy measures in place, it would need to consider service level agreements with DNSPs to manage the risk of system failures leading to customer supply issues. This would also be needed if a DNSP engaged a third-party technology provider to manage their own systems for communicating DOEs.

Compensatory controls tested in Project EDGE (48 hour rolling window for DOEs, which could be longer if industry deemed it necessary, and default DOEs) enabled VPPs to continue to operate within network limits even after not receiving DOEs for six days. Similar compensatory controls should be considered by industry in the design of a DER data hub

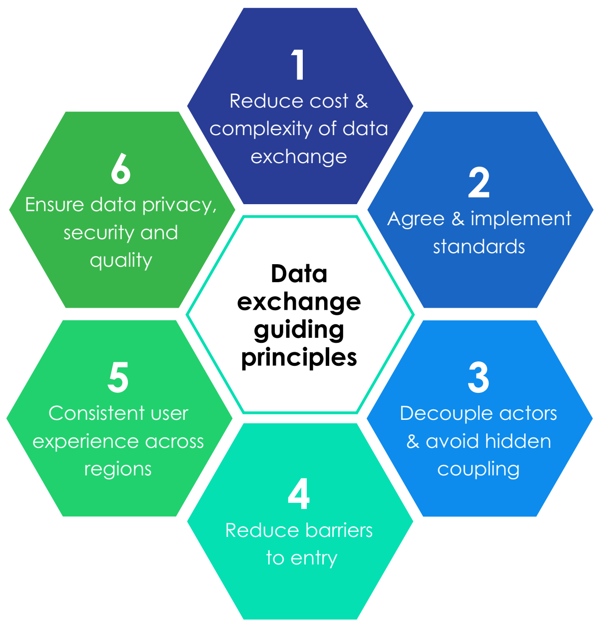
6.3.4 A phased implementation approach is preferred by industry

Collaboration across industry will be needed to design, develop and implement a DER data hub

As previously mentioned in section 6.3.1.1, if a decision is made to implement a DER data hub in the NEM, the first priorities would be to consider the design principles, policy objectives and current/future DER data exchange use cases. These elements would shape the high-level design of a NEM DER data hub. The figure below shows the data exchange design principles that were agreed by the Project Participants at the outset of Project EDGE.

Figure 98: Project EDGE data exchange design principles

Data exchange design principles



Principle	Considerations
1	How can the industry wide costs and complexity of exchanging data between many parties be reduced through standards or common digital infrastructure?
2	Agree between Project Participants what data standards should be used.
3	Aim to avoid point-to-point connections between actors (tight coupling), or market operator and DNSP sending simultaneous but conflicting signals to the aggregator (hidden coupling).
4	Make it as easy as possible for aggregators to connect with the market operator and multiple DNSPs to exchange data. Find alternatives to the expense of connecting to Supervisory Control and Data Acquisition system (SCADA) for sending operational data.
5	Enable aggregators to have consistent user experiences when sending data to multple DNSPs or the market operator.
6	Ensure appropriate standards are upheld regarding data privacy, cyber security and data quality.

A new set of design principles would need to be developed among industry for a NEM DER data hub, together with policy objectives on whether the DER data hub ownership, governance, operating and cost recovery models should be centralised with AEMO, shared amongst industry participants or a blended approach adopted.

These decisions should be the subject of broad consultation with industry to identify the logical initial use cases, participants and location for a potential first deployment of a DER data hub, and accelerate this process if required to align with industry timelines – for instance, if there is a target deadline for communicating DOEs at scale.

Once these high-level decisions are agreed, the full spectrum of technology options can be considered through a competitive market sounding and procurement process so that the most appropriate technology architecture and design choices are made to align to the high-level design.

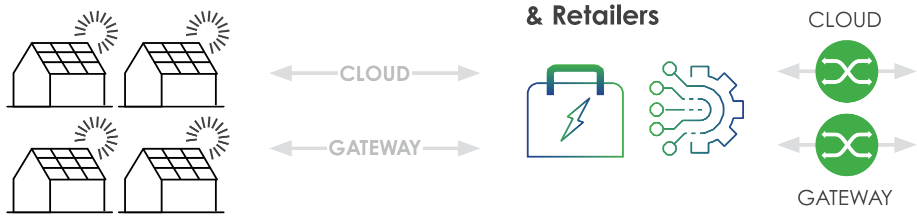
Figure 99 shows a conceptual view of what a DER data hub could look like beyond Project EDGE, including DER connecting natively to the DER data hub (as described in section 6.3.2), enabling customers' DER to receive DOEs and coordination tariff signals from DNSPs and dynamic export limits from retailers whether they are enrolled in a VPP or not.

The figure also shows a range of initial data exchange use cases that could be supported by a DER data hub. Note that Project EDGE also tested the exchange of wholesale bi-directional offers and dispatch instructions, as well as local NSS event triggers through the EDGE data hub solution. These are not included in the initial use cases as bidding and dispatch instructions currently occur through AEMO market systems and timing for wide-spread adoption of NSS by DNSPs is unclear at this stage. Notwithstanding, it is envisaged that these capabilities could be added to an industry DER data hub as required in future.

Figure 99: Conceptual view of a DER data hub beyond Project EDGE

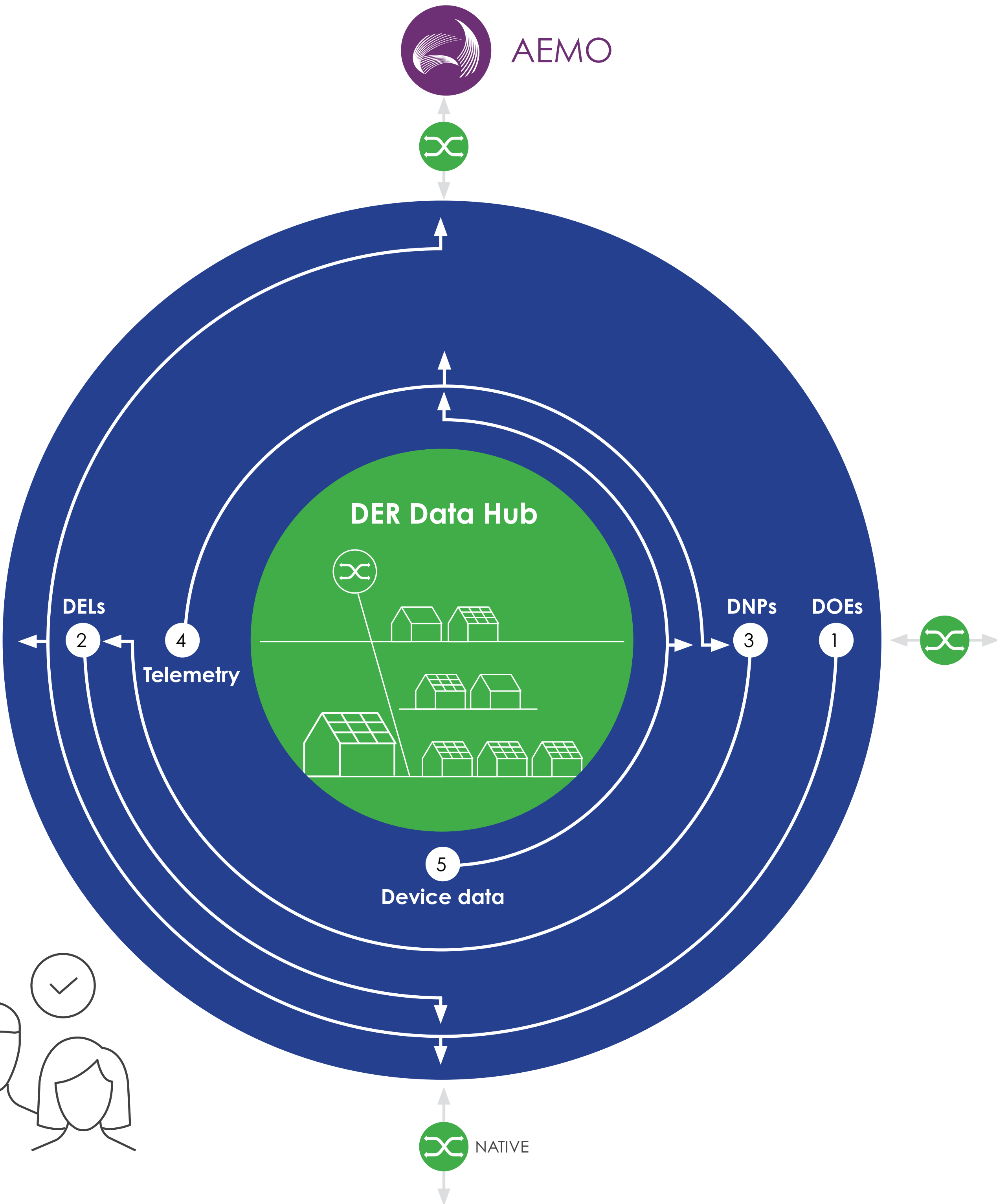
VPP customers

Aggregators & Retailers

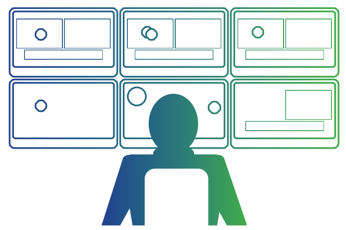


If customers sign up to a VPP, the aggregator) can connect with customers' DER and to the DER Data Hub through a gateway device or through the cloud.

Retailers can also send signals (e.g. dynamic export limits) to customers whose DER is natively connected to the DER Data Hub



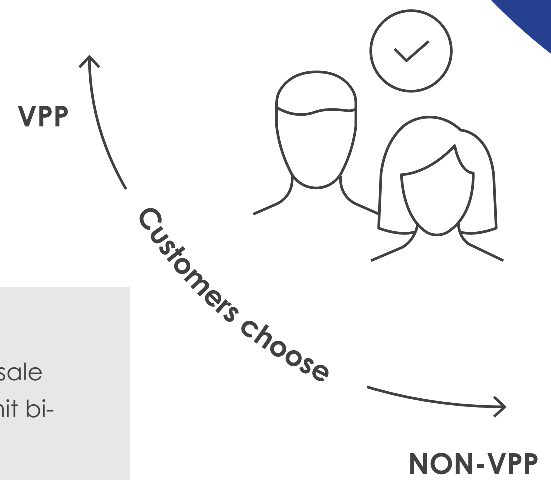
Distribution system operator



DSOs use the DER Data Hub to:

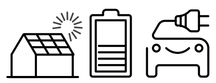
- Send DOEs, or dynamic tariff/price signals
- View updates to standing data/inverter settings to monitor standards compliance
- Send dispatch signals and receive telemetry relating to contracted network support services

#	Use case description
1	**DOEs** = Dynamic Operating Envelopes. This includes Co-Ordination Tariffs signals that may send targeted DOEs (e.g. to coordinate flexible loads). Sent from DSOs to DER devices, Aggregators and AEMO (for visibility)
2	**DELs** = Dynamic Export Limits. Sent from Retailers to DER devices
3	**DNPs** = Dynamic Network Prices. Sent from DSOs to Aggregators.
4	**Telemetry** = performance measurement data for VPP portfolios. Sent from Aggregators to AEMO and DSOs.
5	**Device data** = standing data submitted on installation plus updates to settings and firmware over time.



Key points to note

- **Wholesale services:** Beyond Project EDGE it is envisaged that VPPs participating in the wholesale market would use existing NEM systems to submit bi-directional offers and receive dispatch targets.
- **Local Network Support Services (NSS):** It is not envisaged that there is an immediate need for digital solutions to procure local NSS at scale. Immediate actions could be focused on how to how to standardise NSS trade.



Non-VPP customers' DER

Customers connect their DER to the DER Data Hub natively on installation, and choose whether to join a VPP or not.

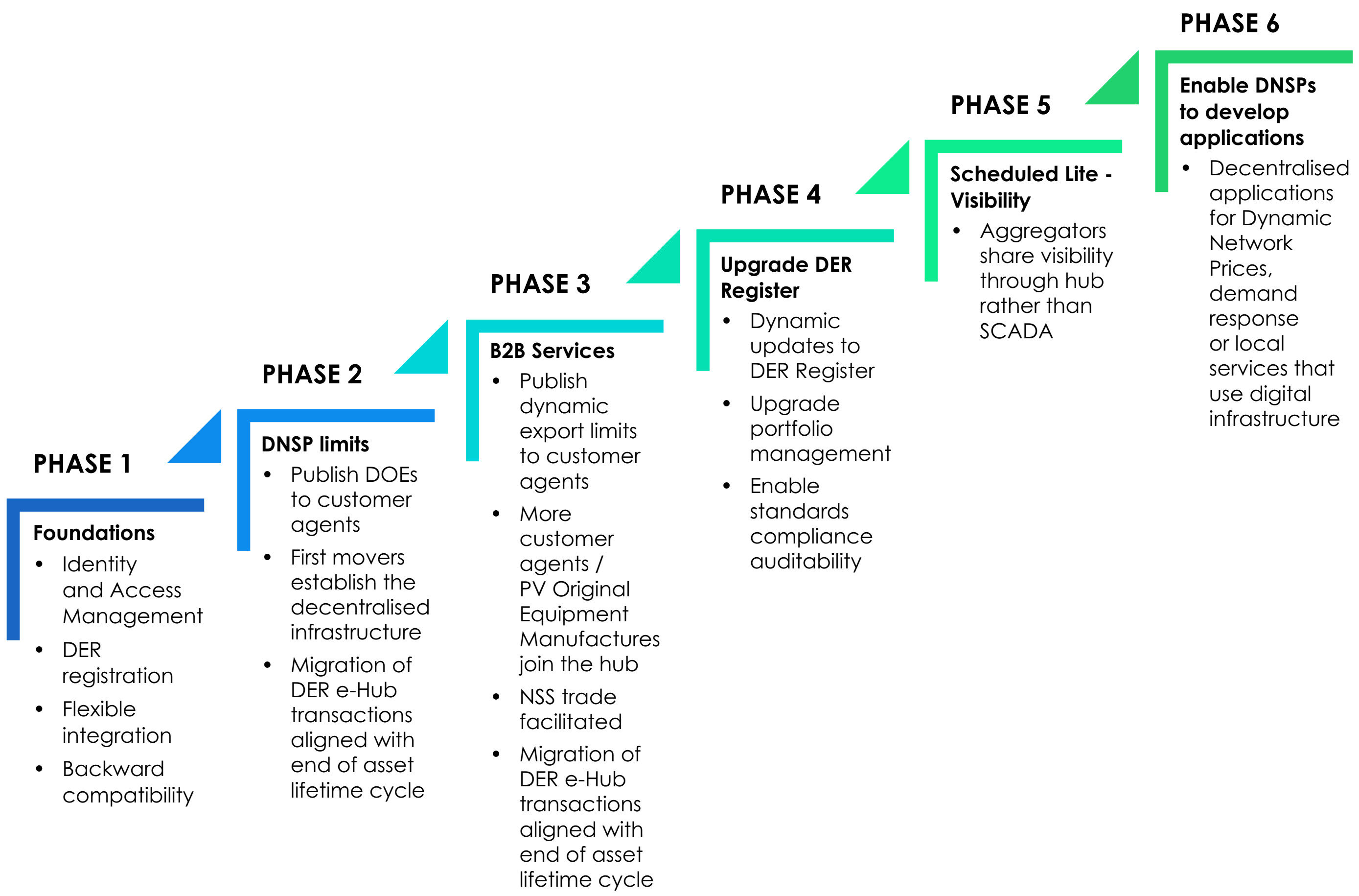
Natively connecting to the DER Data Hub will enable their DER to receive DOEs from DNSPs or dynamic export limits from retailers without joining a VPP.

It is important to consider how a phased implementation may be more appropriate than a single 'big bang' implementation. A successful small-scale implementation for an initial use case may pave the way to add further use cases and participants over time.

Planning for future use cases could form a phased implementation roadmap, including use cases in adjacent sectors that may deliver greater efficiency gains for consumers. For example, sharing of standing and operational data from EV charge points, particularly since charge points would need to receive DOEs from DNSPs in future.

A high-level conceptual roadmap for a phased implementation is shown Figure 100.

Figure 100: Conceptual roadmap for phased implementation of DER data hub



A phased implementation of a DER data hub and next steps may include:

- Identify policy objectives, design principles and future use cases for a NEM DER data hub
- Identify appropriate use cases and voluntary participants for a phase 1 implementation
- Develop detailed design for a minimum viable product (for phase 1 implementation), that includes Enterprise and Solution Architecture (conceptual and logical)
- Detailed design should consider the full spectrum of technology options to meet the policy objectives, design principles and future use cases for a NEM DER data hub, considering the option value of flexible solutions that can transition to alternative approaches (such as decentralised components) as needed in future
- Design a detailed implementation roadmap on which use cases could be added and when
- Link with other activities, such as the development of Public Key Infrastructure for DER, the national EV strategy[279] and the National Charge Link[280] proposal, to identify opportunities to integrate initiatives to deliver more efficient outcomes.

279 Australian Government. 2023, National Electric Vehicle Strategy: Increasing the uptake of Evs to reduce our emissions and improve the wellbeing of Australians. https://www.dcceew.gov.au/energy/transport/national-electric-vehicle-strategy

280 RACE for 2030 CRC. 2022, N1 Project design consult – National Charge Link Final Report. https://racefor2030.com.au/reports-by-year/

281 The NEM2025 Program was formed by AEMO to manage the implementation of the Energy Security Board's post-2025 electricity market design reform package. AEMO. N.d., About the NEM Reform Program. https://aemo.com.au/initiatives/major-programs/nem2025-program/about-nem2025-program

These activities could all be progressed within the broader context of the Industry Data Exchange and DER data hub and Register projects in the NEM2025 Program,[281] and should be done so through engagement with industry stakeholders.

6.3.5 New data exchange capabilities are required to maintain power system security in a high DER NEM

New capabilities related to DER data exchange should be considered in the design of a DER data hub

Beyond testing the DER data hub concept, Project EDGE also identified a range of new capabilities related to DER data exchange that are required to support power system security in a high DER NEM. These are discussed below and should be considered in any future DER data hub design.

6.3.5.1 Layered intelligence capabilities can enhance system security

Stakeholder engagement during Project EDGE identified that in a high DER future, AEMO and DNSPs will need access to mechanisms to isolate and potentially disconnect DER that pose an untenable risk, if necessary – for example, in the event of a cyber-attack or public internet failure. AEMO may not enact these measures directly but could direct other parties to act.

These capabilities can be enabled through a power system architecture with layered intelligence at device level, smart meter level and network level that support 'security by design'.

Layered intelligence could be represented by:

- DER operating autonomously and predictably in a communications outage using local controls to remain within a previously downloaded DOE profile, or to operate under known compensatory controls settings
- DER reverting to a self-consumption or 'self-dispatch' mode in the event of widespread communications outage (see section 5.3.2.6 and section 5.3.2.7)
- In a system black event, DER devices may need to remain switched off, at zero export or even zero generation (depending on whether the DER are located on the restart pathway), until a signal is sent that normal service can resume[282]
- Smart meters may support real-time DOE conformance monitoring (as outlined in section 8.3.4.4) or the isolation and disconnection of metering elements in a suspected cyber-attack. Separation of controllable load, generation and passive load at a site can unlock and future-proof additional use cases, such as targeted load or generation shedding aligned to customer preferences. The use of smart meters for monitoring was considered as part of the AEMC's review of the regulatory framework for metering services and is worth exploring further.[283]
- Automated arming and triggering of local network services, triggered by DNSP control rooms, to manage forecast network constraints.

6.3.5.2 More cyber security measures are required for DER

EY conducted a cyber security threat assessment on the data exchange approaches.[284] The assessment reviewed a number of potential cyber security risks associated with DER data exchange generally (i.e. not risks relating specifically to a DER data hub) and outlined mitigating controls that could result in a lower residual risk level.

The following key risks and mitigating controls were identified:

282 AEMO's determination of electrical sub-network boundaries is a required activity for AEMO defined with the NER cl. 3.11.8. Under current arrangements, the power system requires a block of stable loads in order to restart after a blackout via defined restart pathways (particular sub-networks that include specific transmission lines and feeders to link to another generator and sensitive load centres). DER disrupts these stable load blocks, particularly distributed PV, making the challenge of system restart more difficult. AEMO's determination of electrical sub-network boundaries is a required activity for AEMO defined in the NER, clause 3.11.8.

283 AEMC. 2023, Review of the regulatory framework for metering services, p.122 and Appendix E.4.1. https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_metering_review_-_final_report.pdf

284 EY. 2023, Project EDGE: Technology and Cyber Security Assessment May 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

- **Vulnerabilities and weaknesses in the multiple software ecosystems leveraged in the DER ecosystem could lead to unauthorised access to disclosure of sensitive information.**
  - Given the nature of DER, weaknesses and vulnerabilities in the software/application eco-systems leveraged across industry participants could negatively impact the confidentiality, integrity and availability of information.
  - Therefore, secure application development processes should be leveraged wherever possible, and appropriate application security controls should be developed and administered for all key software components across the DER ecosystem.
- **Lack of appropriate management of supply chain risks could lead to data disclosure or unavailability of key DER resources.**
  - Each DER industry participant would have their own supply chains based on their business requirements. Such supply chains provide a threat actor with opportunities to perform malicious activities targeting specific DER entities.
  - Cyber security requirements should be established for key suppliers according to industry better practices and information sources should be monitored to identify and address supply chain threats and risks.
- **Lack of asset and entity classification processes could lead to inappropriate application of security controls thereby increasing the impact of a potential cyber-attack.**
  - Multiple entities operating across the DER ecosystem have critical assets.[285] In the event of a security incident affecting these critical assets, lack of appropriate security controls could lead to significant impact to the confidentiality or availability of the affected entity.
  - Each entity across the DER ecosystem should perform a Business Impact Analysis (BIA) to understand the criticality of their assets and implement appropriate controls to ensure critical assets have the right level of protection against cyber-attacks.
- **Weaknesses in security operations could lead to cyber-attacks not being identified or having greater impact.**
  - A DER data hub would be designed to have bi-directional flow of information, with each single entity having significant amount of customer and operational data at a given point in time. Due to the interconnectedness of the DER data hub, a compromise of a single entity could have significant impacts across the DER data hub.
  - Consolidated visibility over malicious activity and security incidents across the DER data hub, and capabilities to detect, isolate, defend and recover from such incidents can mitigate risks that may impact the confidentiality and availability of data.
- **Attacks could occur due to weak transmission and communication protocols.**
  - Protocols facilitate the communication and transmission between DER devices, aggregators, DNSPs, DSOs and other entities across the DER ecosystem.
  - Secure communication and transmission channels should be established for communications and transmissions between these entities. At the time of writing, there are multiple protocols that could be used to integrate DER such as IEEE 2030.5, Modbus, LoraWAN and IEEE 1815.
  - DNSPs in Australia have collaborated to align to IEEE 2030.5 and CSIP-AUS. The ESB's Interoperability Directions paper also explored the need for a national approach to public key infrastructure, both the IEEE 2030.5 and for future EV related standards.[286]
  - Integrity of communications should also be considered between devices and entities across the DER data hub and independent verification processes should be implemented to ensure integrity.
- **Compromised DER data hub entities and critical assets could lead to loss of services.**
  - In an event where a DER data hub entity or a critical asset at an entity were compromised, it could lead to loss of services.
  - As with any system, not just a DER data hub, entities should have appropriate monitoring and alerting processes, Incident Response plans and Disaster Recovery processes.
  - Redundant technologies and device compensatory controls should be implemented for critical assets and processes. See section 5.3.2.6 for a discussion on the testing of operational compensatory controls for VPPs. The United States Department of Energy's Cyber-Information Engineering (CIE) framework provides guidance on building cyber security practices into the design life cycle of engineered systems to mitigate impacts of a cyber incident.[287] The framework's emphasis on 'Assume Compromise' drives requirements for appropriate detection, isolation and mitigation of cyber risks.
  - Each entity across the DER data hub should also have an asset classification framework. Having an asset classification framework enables consistent application of risk management processes, as well as security controls, across critical and high-value assets. The SOCI Act (Security of Critical Infrastructure Act 2018) mandates recording and reporting of critical and high-value assets.

Stakeholder engagement with aggregators during Project EDGE identified that most aggregators are focused on protecting their systems from cyber risks, but there is a gap in capabilities that 'assume compromise' and extend protection to also monitor, detect, isolate, defend and recover from cyber security risks. Stakeholder engagement also identified broad support for cyber security standards to be developed and implemented, beyond the voluntary approach to the Australian Energy Sector Cyber Security Framework.[288] Adoption of cyber security standards can include the mitigations identified. The process of implementing cyber security standards could progress independently of the development of a DER data hub as they are mitigations relevant to cyber security in a high DER future whether or not industry chooses to use a DER data hub approach.

With respect to cyber security of a DER data hub itself, some stakeholders expressed a concern that a DER data hub could represent a single point of failure and increased cyber security risk. However, a DER data hub can be more efficient in that it may be more cost-effective to focus resources on providing redundancies and security measures for a DER data hub as critical infrastructure than providing the same level of security across multiple DNSP and retailer systems, as would be required in a point-to-point approach.

6.3.5.3 A consistent approach to compensatory controls is required

Compensatory controls define DER behaviour, and communications redundancy requirements, in the event of a communications failure or loss of trust in one or many market participants.

To aid network planning, control and operations, compensatory control parameters should be defined at the time of DER registration in the DER data exchange ecosystem (for market and/or non-market services). These compensatory controls will be needed whether or not industry chooses to use a DER data hub. In the future, these parameters should be considered in how to best manage the quality, safety and reliability and security of the supply of electricity.

In addition to the field testing of compensatory controls for a group of coordinated DER – that is, VPP behaviour (see section 5.3.2.7) – Project EDGE's analysis of compensatory controls considered Australian and International device standards. AS/NZS 4777.2, an existing engineering standard for behaviour and expected performance of inverters at low voltages (such as households or small-scale commercial), as well as IEEE 2030.5, a standard for communication between smart grid and consumers, were assessed.

Compensatory controls are built into the AS/NZS 4777.2:2020 that define the conditions in which inverters should stay connected and generating power to the electricity grid, or disconnect to support power system security and prevent major events. These conditions, including speed of isolation and islanding, will likely be triggered in a power outage or loss of supply to the connected device.

285 Section 8D of the Security of Critical Infrastructure Act 2018 defines the energy sector of the Australian economy as a critical infrastructure sector.
Security of Critical Infrastructure Act 2019, section 8D. https://www.legislation.gov.au/Details/C2022C00160

286 ESB. 2022, Interoperability Policy for Consultation Directions Paper. https://www.datocms-assets.com/32572/1665556228-interoperability-policy-directions-paper-final.pdf

287 Office of Cybersecurity, Energy Security, and Emergency Response. US Department of Energy. 2022, National Cyber-Informed Engineering Strategy from the U.S Department of Energy. https://www.energy.gov/sites/default/files/2022-06/FINAL%20DOE%20National%20CIE%20Strategy%20-%20June%202022_0.pdf

288 Australian Government. N.d., Australian Energy Sector Cyber Security Framework. https://www.energy.gov.au/government-priorities/energy-security/australian-energy-sector-cyber-security-framework

289 AEMO. 2022, Review of Power System Data Communication Standard. https://aemo.com.au/en/consultations/current-and-closed-consultations/review-of-power-system-data-communication-standard

290 The Power System Data Communication Standard defines an Intervening Facility as being a Data Communications Facility that is required or permitted to transmit operational data directly to and from an AEMO coordinating centre under the standard. An Intervening Facility does not include any facility or service provided by AEMO for communication between an Intervening Facility and an AEMO coordinating centre. AEMO. 2023, Power System Data Communication Standard, p.26. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/AEMO-Standard-for-Power-System-Data-Communications.pdf

The IEEE 2030.5 defines the behaviour and expected outcome in the case of loss of communication, – that is, the loss of DER data exchange. An example of an engineering control for communication networks is in AEMO's standard for Power System Data Communication 2022,[289] where power system data exchange must be capable of remaining operational for up to 10 hours following loss of external AC supply. A similar requirement may be proposed for telemetry of data between the individual remote monitoring and control equipment and a data communications facility.

This requirement may also apply to the Intervening Facilities[290] themselves. Variations to these requirements may be required for smaller participants connecting directly to AEMO, subject to individual and regional significance. With this consideration, compensatory controls should be able to be triggered even without external AC supply; for example, in the event of a communications network outage.

As part of network planning and DER connections, DNSP's should also identify appropriate protection and compensatory control processes for DER.

CASE STUDY

SA Power Networks example of compensatory controls

An example of an implementation of compensatory control is SAPN's Flexible Exports program, where SAPN have adopted the IEEE 2030.5 (Smart Energy Profile 2.0), a standard for communication between smart grid and consumers.[291]

This standard is built using Internet of Things (IoT) concepts and gives consumers a variety of means to manage their energy use and generation. Information exchanged using the standard includes pricing, demand response and energy use, and enables the integration of a variety of DER devices such as smart thermostats, meters, plug-in EVs, smart inverters and smart appliances.

SAPN has utilised IEEE2030.5's DefaultDERControl control mode as a failsafe to revert DER to minimal export on the loss of communications. IEEE2030.5 defines DefaultDERControl as the control mode information to be used if no active DERControl is found. Note that this form of compensatory control is for loss of communications; if the DER has been compromised by a cyber-attack, this function for compensatory control would not apply.[292]

SAPN are using this standard to communicate flexible export limit schedules to customer agents and DER devices.[293] These schedules typically run for a 24-hour rolling window, and devices regularly receive new export limit schedules from the SAPN system. If devices lose communications (for example, internet), then it is expected that the device will continue operating using the most recently downloaded schedule.

The DefaultDERControl setting is configurable and can be changed based on prevailing circumstances, and devices would have this setting updated the next time they download it. Currently, SAPN's DefaultDERControl setting curtails export limits based on a 1-hour scale decaying confidence schedule. This means that after two hours without communication, the controlled device will revert to minimal export, failsafe mode (diagram below).

Figure 101: SAPN's DefaultDERControl settings in the flexible exports program

This procedure implements effective controls to curtail DER export with an extended loss of communication, ensuring system security with the existing level of DER penetration. Currently, if there is an extended communication network outage, SAPN provide AEMO a static view of the expected loss of generation for that outage (for example, 2 hours after the communication outage)

It is important to consider that, with greater penetration of DER, this procedure may need to be further developed. SAPN confirmed through stakeholder engagement that they are assessing how the DefaultDERControl procedures can be updated with greater levels of DER penetration. This may include the development of an operational procedure between SAPN and AEMO control rooms, or dynamic communication between SAPN and AEMO to agree different DefaultDERControl settings to apply under different seasons or operating conditions (see related key learning from the AoLR case study in section 5.3.2.6).

291 Aurecon. 2021, Flexible Exports for Solar PV: Lessons Learnt Report 3 - SA Power Networks Reference 2020/ARP009, p 13, section 3.3. https://arena.gov.au/knowledge-bank/flexible-exports-for-solar-pv-lessons-learnt-report-3/

292 The South Australian Government has also introduced regulatory changes under the Smarter Homes program relating to new technical standards and requirements for smaller generating systems such as rooftop PV. This includes requirements for systems to be capable of export limitation and being remotely disconnected and reconnected by a relevant agent. Additionally, smart meters must be able to separately measure and manage generation and controlled load.

Government of South Australia. N.d., Regulatory changes for smarter homes.https://www.energymining.sa.gov.au/industry/modern-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes

293 This is a first step toward a dynamic operating envelope.

SA Power Networks. N.d., Flexible Exports.https://www.sapowernetworks.com.au/industry/flexible-exports/

As compensatory control settings are agreed and defined in connection agreements, there may also be a need for testing of these settings on connection and as part of ongoing periodic compliance testing. Project EDGE tested a compensatory control for VPPs through the application of a default DOE that was set at enrolment. See section 5.3.2.7 for a discussion on the compensatory control capabilities aggregators will require to integrate and participate in the electricity wholesale market.

INSIGHTS

Consistent approaches to compensatory controls

A consistent approach to compensatory controls is critical to maintaining system security in a high DER future. Consistency could be achieved through AEMO working with DNSPs so that:

- The design of compensatory controls is coordinated to avoid duplicate or contradictory controls (for example, AEMO could apply some controls to VPPs while DNSPs may apply some controls through DOE implementation). The coordination of design should consider the hierarchy of interventions proportional to the magnitude of risk posed to the power system
- AEMO and all DNSPs adopt a consistent approach to DER compensatory controls, so DOEs and other market processes can still be applied even when communications are lost
- An operational procedure between DNSPs and AEMO control rooms is developed as DER penetration gains further scale to communicate the settings applied and impact of an extended communication outage on coordinated DER operations
- There shared visibility of different default DER control settings that apply under different seasons or operating conditions, if appropriate
- Appropriate testing and conformance monitoring approaches for compensatory control settings for VPPs and DOE-enabled devices are agreed and implemented.

See section 5.3.2.7 for a discussion on compensatory controls.

6.4 Key insights and implications for industry

Work undertaken for Project EDGE confirmed the hypothesis that a DER data hub approach is more efficient, scalable and aligned to the long-term interests of consumers than a point-to-point approach. However, a number of issues need to be addressed in progressing the design and implementation of a data hub.

Project EDGE notes the following key insights and implications for industry.

For policy makers

- Explore the concept of a DER data hub and decide whether a DER data hub approach should be pursued by industry.
- On the assumption a data hub approach is progressed, in collaboration with AEMO, consider whether the DER data hub initiatives in AEMO's NEM2025 Program, specifically the DER Data Hub and Registry Services and Industry Data Exchange projects, are appropriate to support industry collaboration on the development of a DER data hub.
- Link with other activities, such as further investigating Public Key Infrastructure for DER, the national EV mapping tool in the National EV Strategy or the National Charge Link proposal to identify whether integrating initiatives can deliver more efficient outcomes.
- Progress further work on power system architecture with layered intelligence at device level, smart meter level and network level that support 'security by design'.
- Identify appropriate measures to augment cyber security protections for DER and consider including these into a cyber security standard for DER that covers the whole value chain (not just devices).

For AEMO

- If policy makers confirm a DER data hub approach, engage in collaborative planning for a DER data hub through AEMO's NEM2025 Program – specifically the DER Data Hub and Registry Services and Industry Data Exchange projects. Planning activities should include consideration of design principles and policy objectives for a NEM DER data hub; in particular:
  1. Ownership and cost recovery
  2. Governance
  3. Operation, innovation and development
  4. Connectivity and use case.
- Collaborate with policy makers to define design principles and policy objectives for a NEM DER data hub.
- Engage in discussion with a broad range of parties in the DER data hub collaboration process to understand the various industry, customer, and other stakeholder perspectives on the concept of a NEM DER data hub.
- Identify appropriate use cases and voluntary participants for a phase 1 implementation.
- Develop detailed design for a minimum viable product (for phase 1 implementation) that includes Enterprise and Solution Architecture (conceptual and logical). Detailed design should align to the design principles and policy objectives set by policy makers and industry leaders. Detailed design should present technology options suitable for critical infrastructure and should consider the option value of solutions that can enable a transition to alternative approaches as needed in future.
- Design a more detailed implementation roadmap on which use cases could be added and when, in collaboration with industry and in alignment to their needs.
- Consider requirements for stakeholder engagement and educational materials to explain the need, purpose, objectives and design options for a DER data hub to a broad audience.
- Collaborate with DNSPs on the design of DER and VPP compensatory controls to avoid duplicate or contradictory controls. The coordination of design should consider the hierarchy of interventions proportional to the magnitude of risk posed to the power system.

For DNSPs

- If policy makers confirm a DER data hub approach, engage in the industry discussion to put forward DNSP perspectives on the concept of a NEM DER data hub.
- Collaborate with each other and AEMO to develop an operational procedure between DNSP and AEMO control rooms as DER penetration gains further scale to communicate compensatory control settings applied and the expected impact of an extended communication outage on coordinated DER operations.
- Engage with other DNSPs and AEMO to adopt a consistent approach to DER compensatory controls, so DOEs can still be applied even when communications are lost.
- Collaborate with AEMO on the design of compensatory controls to avoid duplicate or contradictory controls. The coordination of design should consider the hierarchy of interventions proportional to the magnitude of risk posed to the power system.
- Collaborate with each other and AEMO to agree different default DER control settings to apply under different seasons or operating conditions, if appropriate.
- Collaborate with each other and AEMO to agree appropriate testing and conformance monitoring approaches for compensatory controls settings for VPPs and DOE-enabled devices.

For aggregators

- Engage in the industry discussion to put forward aggregator perspectives on the concept of a NEM DER data hub.
- Engage with DNSPs and AEMO to agree appropriate compensatory control settings and approaches.

LOCAL NETWORK SUPPORT SERVICES

This chapter focuses on the research question:

How can integrating DER into the NEM facilitate efficient and scalable provision of local network support services (NSS) from DER so that network efficiency benefits are realised for all customers?

Overview

- In future, the net zero transition could cause increasing peak demand network congestion. One way to manage peak demand constraints is through contracted network support services (NSS), such as procuring specific and firm quantities of generation/demand reduction at a specific location and time to manage a constraint. From a DNSP perspective, NSS could offer an efficient way to save network costs for consumers by deferring the need to build out the network.
- As DNSPs procure NSS services at higher volumes of capacity and transactions, digital solutions could improve the efficiency and scalability of these services. Project EDGE designed a digital solution called a Local Services Exchange (LSE) and built and field trialled an LSE with two aggregators.
- An LSE acts as an interface between DNSPs and aggregators and covers the lifecycle of NSS from identifying the network constraint and defining service characteristics and requirements through to delivering the service and verifying how the service performed in addressing the constraint.
- Project EDGE tested a model in which DNSPs could design and operate (or outsource if preferred) an LSE solution that is connected to a DER data hub to facilitate standardised data exchange.
- Overall, the Project EDGE field trials have shown technical capability (at small-scale) for coordinated DER to provide local NSS that a DNSP could use to manage network constraints. In particular, the field trials indicated that aggregators could reliably deliver firm network services while also 'value stacking' with wholesale services.
- The UK experience suggests that 'market failures' can restrict the ongoing growth of NSS. To address these potential obstacles ahead of increased DER In the NEM, development of scaled NSS trade would need to be facilitated through the development of standardised frameworks, streamlined contract processes and mechanisms for transparent decision-making.
- The LSE field trials uncovered other factors that aggregators may need to manage to successfully deliver local NSS. These include the development of capacity forecasting capabilities; considerations of customer type, load profile accuracy and location of customer sites within the LSE portfolio; building service resilience; managing communications outages; and thoroughly testing DER device capabilities.
- Project EDGE has also demonstrated that an LSE could help standardise NSS trade. The project showed the concept of defining and standardising the characteristics of common NSS is feasible. It also showed that the data for demand-related NSS can be exchanged successfully between DNSPs and aggregators through a DER data hub.
- Standardising how local NSS are defined, transacted and 'stacked' with other services would mean that aggregators operating across the NEM can transact for a similar service in similar way with any DNSP across the NEM. Aggregators could more easily scale delivery of NSS across regions, and DNSPs would have a larger capacity of NSS available to defer network investment.
- A nationally consistent approach to delivery of NSS would make it easier for aggregators to scale across networks, delivering greater value to consumers.
- Policy makers should consider exploring an LSE framework connected to a DER data hub model to facilitate procurement of local NSS and VPP participation to begin scaling.
- The design of the LSE framework should also consider how TNSPs could use the LSE to procure network support services in the future.

7.1 Context

The forecast high capacity of coordinated DER in the NEM presents opportunities for:

- Aggregators to value stack revenues streams and share greater value with their customers.
- DNSPs to utilise DER as an alternative to reinforcement solutions to manage their electricity networks, thereby deferring or displacing the need to build out the network to address network congestion.

In the UK in 2022, distribution networks tendered for almost 4GW of flexibility services[294] from distribution-connected resources[295] to manage peak demand congestion and defer network augmentation. A rapid transition towards a net zero economy, and a rapid uptake of EVs and heat pumps in particular, is increasing network constraints in peak demand periods (cold winter evenings), driving a need for distribution flexibility services.

The Australian context for distribution network support services (NSS) is different. The most pressing distribution network constraints in the NEM relate to peak solar PV exports on mild, sunny spring/autumn days. Currently, these constraints are being managed through a transition towards dynamic connection agreements and flexible export limits, rather than network support services.

DEFINITION
Network support services (NSS)

Network support services (NSS) refers to energy services that a DNSP or DSO procures to manage network constraints. Examples include an increase or decrease in demand, or voltage management services.

In future, the net zero transition,[296] including a rapid uptake of EVs,[297] could cause increasing peak demand network congestion. There are various ways to manage peak demand constraints until a need for network augmentation can be demonstrated, including:

- Cost reflective tariffs, including time of use tariffs (e.g. to encourage EV charging away from peak demand periods) or dynamic network pricing
- Alternative policy drivers, such as mandating EV smart charging
- New types of network tariffs such as the diversity tariff being trialled by SA Power Networks,[298] in which DNSPs provide direct and ongoing compensation to customers (about $120 per annum) if they enrol their DER to receive a targeted DOE (a flexible import limit) during a peak demand event

294 Energy Networks Association (UK). N.d., Flexibility Services. https://www.energynetworks.org/creating-tomorrows-networks/open-networks/flexibility-services

295 The UK does not have the same penetration of LV connected DER. The service providers for these tenders are mostly utility-scale resources that are connected to the distribution network, or commercial and industrial customers, rather than residential DER.

296 Australian Government. 2022, Australia Legislates Emissions Reduction Targets [media release], 8 September 2022. https://www.pm.gov.au/media/australia-legislates-emissions-reduction-targets

297 Graham P for CSIRO. 2022, Electric vehicle projections 2022: Commissioned for AEMO's draft 2023 Input, Assumptions and Scenarios Report. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf

298 SA Power Networks. N.d., Trial Tariffs 2023-24. https://www.sapowernetworks.com.au/public/download.jsp?id=320663

- Contracted network support services – for example, to procure specific and firm quantities of generation/ demand reduction at a specific location and time to manage a constraint.

The extent to which NSS will be procured at scale to manage a high volume of network constraints, and the timing of when this could occur, largely depends on the extent to which other measures in the list above are trusted and used by consumers.

Further work is required to understand consumer perspectives on flexible import limits, and whether consumers have different perspectives if the limits are applied on their entire household load or on specific flexible devices, but these limits will eventually be required to manage system security (see the example case study in the box below).

CASE STUDY

Managing 'super-peaks' in a highly electrified future

Consider a future scenario where residential and commercial energy use is largely electrified. On day 2-3 of a summer heatwave that is already pushing peak demand records, a forecast evening thunderstorm may cause consumers to simultaneously use major appliances for cooking, cooling and charging up their cars/stationary batteries ahead of the storm rolling through, causing a 'super-peak' in electricity demand.

In this scenario, AEMO and DNSPs may need to enact emergency flexible import limits to maintain system and local network security, as it may be inefficient to build out network infrastructure to cater for this infrequent scenario, and curtailing flexible loads in an emergency may be preferable to indiscriminate load shedding.

This could be a new type of flexible load 'emergency backstop' that could be implemented before widespread, indiscriminate load shedding.

Network support services (or local 'flexibility' services) could be triggered to reduce flexible loads, address localised peak demand congestion or triggered in advance of an 'emergency backstop'.

While the timing of when DNSPs may need to procure local NSS at scale is uncertain, it is logical that these 'flexibility' services will play a role as the economy electrifies.

DNSPs are already obliged (under NER clause 5.15.2(c) and AER guidelines)[299] to consider NSS against all credible options without bias, when considering how to manage material network constraints in a regulatory investment test for distribution (RIT–D). Some DNSPs also consider NSS to manage network constraints when network options are below the RIT-D investment threshold.

From a DNSP perspective, NSS could represent an efficient way to save network costs for consumers by deferring the need to build out the network. However, there are key factors that DNSPs need to consider:

- Can the provider deliver the volume of service to manage the network constraint or will more than one service provider be required (e.g. multiple VPPs)?
- Can the service be delivered consistently and reliably so that the DNSP can rely on the service to defer/ displace network investment?
- What is the value of the service? How much are DNSPs willing to pay (the ongoing cost to manage the constraint must be cheaper than alternative network options) and is this sufficient to attract service providers such as DER aggregators?
- How can services be traded more efficiently compared to the current bespoke, bilateral negotiations that carry high transaction costs?

299 AER. 2022. Application Guidelines: Regulatory investment test for distribution. https://www.aer.gov.au/system/files/AER%20-%20RIT-D%20application%20guidelines%20-%20August%202022%20-%20uploaded.pdf

The core hypothesis for Project EDGE regarding local NSS is that standardisation of these services can benefit:

- Aggregators, as they could transact for a similar service in a similar way with any DNSP across the NEM (as many aggregators operate across multiple regions). It would make participation more accessible and reduce operating costs, increasing the value available to be shared with DER customers.
- DER consumers, as aggregators would share value with them for the use of their DER. If aggregators can stack more value streams, DER consumers should share in greater benefits.
- DNSPs, as over time standardisation would enable:
  1. Consistency in the costs of services.
  2. More availability of aggregators willing to participate and deliver sufficient services to manage network issues, increasing the overall reliability of local network support services. Competition among service providers is also likely to lower the cost of the services.
  3. Reduced costs compared to using the current bespoke tenders and bid reviews for DER-based NSS, translating to reduced network expenditure and cost savings that can benefit all electricity customers.
  4. Traceability in the cost of procuring operational services to defer capital expenditure. A track record can provide an evidence base to show when the operational costs of managing a constraint may rise above the capital costs of a network solution to resolve it. This evidence base enables the AER to assess and approve subsequent proposals for capital expenditure.

DEFINITION

Standardisation of network support services

Standardisation of network support services can be broadly divided into five main factors:

- **Communicating NSS needs** – how DNSPs communicate current or forecasted requirements to procure NSS, potentially using digital mapping solutions
- **Defining NSS** – the characteristics that define the service being procured, including performance compliance thresholds. The services definitions tested in Project EDGE are in section 7.3.2
- **Transaction terms** – the contractual terms for the transaction and whether it is bilateral (between a single buyer and seller) or facilitated via exchange-level agreements and a clearing house. Project EDGE did not test transaction terms
- **Data exchange** – how different types of data such as standing data, portfolio data, service arming instruction/triggers and operational telemetry to verify performance are exchanged. Data for local NSS tested in Project EDGE was successfully exchanged through the DER data hub
- **User experience** – how different participants interact, through user interfaces, with digital solutions to facilitate the trade of NSS.

As DNSPs procure NSS at higher volumes of capacity and transactions, digital solutions could remove manual processes and support standardisation at each step of the NSS lifecycle.

In Project EDGE, this type of digital solution was called a Local Services Exchange (LSE), but in the UK it is called a DNO Flexibility Market.[300] In each case the digital solution acts as an interface between the DNSPs and service providers and typically supports the following stages of the NSS lifecycle:

300 Ofgem. 2023. Call for Input: The Future of Distributed Flexibility. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

Figure 102: Conceptual lifecycle of local network support services

Aggregator	Local Services Lifecycle	Distribution System Operator
View network constraints and future NSS opportunities		Post constraints & NSS needs, and view DER locations & portfolios
View services and assess whether to enrol		Define service characteristics and contractual terms
Submit enrolment and performance test data		Assess performance test data and pre-approved to participate
Submit offer - if accepted, exchange contracts per pre-agreed terms		Post service opportunity, assess offers from pre-approved participants, exchange contracts
Respond to dispatch signal to deliver service		Schedule service delivery or trigger dispatch
Submit service verification		Download/view data and assess to verify performance
Set up standard queries for reporting		Set up standards query for reporting

7.2 Approach

Recognising the UK and Europe are well advanced of Australia in the use of NSS procured by distribution businesses from coordinated DER, Project EDGE consulted with industry and undertook a literature review[301] of UK Distribution Network Operators (DNOs) and Flexibility Exchange Providers to inform its own conceptual design for the local NSS lifecycle.

Key findings from the literature review are discussed in section 7.3.1.

Informed by international examples, Project EDGE designed built and field trialled a Local Services Exchange with two aggregators.[302] The LSE tested was a concept and digital solution through which:

- A DNSP could communicate the need for NSS based on a review of forecast network operating conditions that identifies demand management needs.
- The DNSP would then review offers made by aggregators to identify the offer(s) that represent the best value and select the offer(s) to deliver the required services.

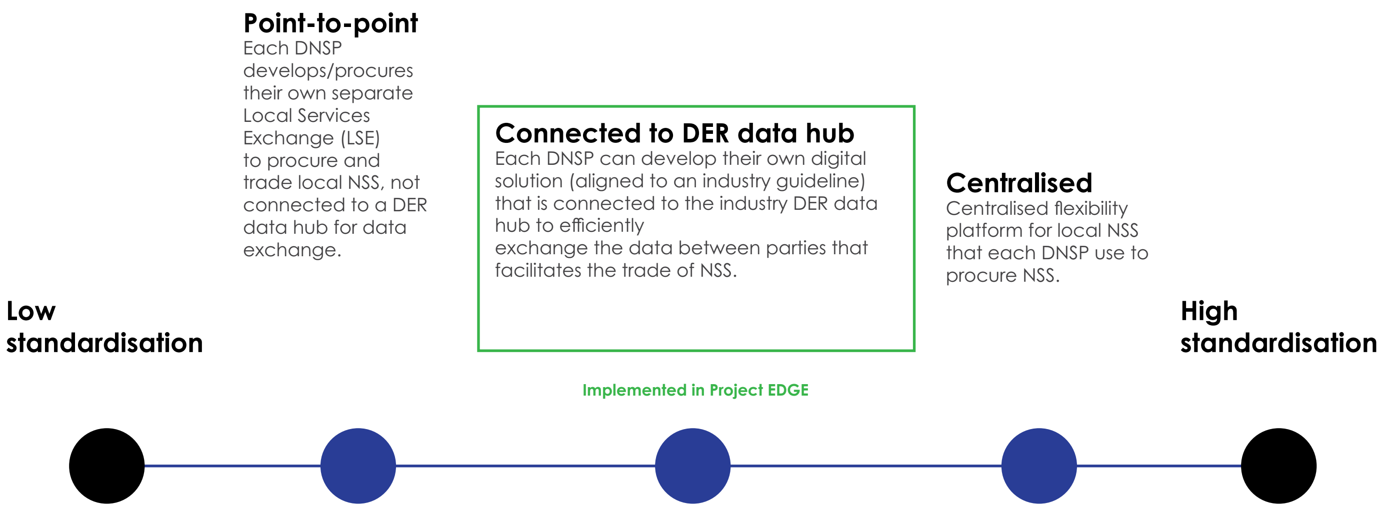
Project EDGE trialled five network support services (see section 7.3.2). Forty-five tests were conducted, noting the following limitations:

- No monetary value was defined for the NSS.
- No monetary incentives were paid for trial participation in the NSS tests.
- The DNSP sent separate service needs to each aggregator. Accordingly, the two aggregators participating in the NSS field tests did not compete with each other to fulfil a service.
- The functionality to place bids for NSS in low price bands to ensure dispatch by AEMO was not accurately built.[303] Nonetheless, the aggregators were able to include their NSS commitments in the wholesale bi-directional offer and simultaneously deliver both services (see section 5.3.2.9).
- All NSS offers were created manually by the aggregator.

7.2.1 Models for NSS procurement at scale

There are different models for how network support services can be procured at scale through different approaches to the design and implementation of an LSE. These models can be shown on a standardisation spectrum, as illustrated in the figure below.

Figure 103: Conceptual models for achieving standardisation in procuring network support services at scale



Standardisation	Low standardisation Point-to-point	Medium standardisation connected to DER data hub	High standardisation centralised
Service definition	Defined by each DNSP differently	Standardised services characteristics defined in an industry guideline that DNSPs co-design and implement	Services are defined (in collaboration with DNSPs and aggregators) with firm specifications in the single centralised flexibility platform
Transaction terms	Defined by each DNSP differently	Standardised contractual terms defined by an industry guideline that DNSPs co-design and implement. Settlement occurs bilaterally outside of DER data hub (i.e. no clearing house)	Terms are standardised and baked into participation on the flexibility platform. Settlement can occur through the platform as a clearing house
Data exchange	Aggregators exchange data directly with each DNSP separately	Multiple LSEs can be connected to the industry DER data hub so that aggregators and DNSPs can efficiently exchange data to facilitate the trade of services	Single LSE is embedded as part of the DER data hub, enabling standardised data exchange
LSE operation	DNSP operated	DNSP or independently operated	Operated by independent party

301 European Power Exchange (EEX). N.d., EEX. https://www.eex.com/en/;
National Grid. N.d., Flexibility & Flexible Power. https://www.nationalgrid.co.uk/smarter-networks/flexibility-and-flexible-power;
NODES. 2023, Nodes. https://nodesmarket.com/;
Ofgem. N.d, Future Insights Series: Flexibility Platforms in electricity markets. https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/ofgem_fi_flexibility_platforms_in_electricity_markets.pdf
Piclo. 2023. Piclo. https://www.piclo.energy/

302 Project EDGE. 2023, Project EDGE High Level Design: Local Services Exchange (LSE). https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge---local-service-exchange-hld.pdf?la=en

303 The bid functionality for Project EDGE was designed so that the quantity offers by the aggregator in its bi-directional offer considered and incorporated any capacity commitments to the DNSP for network support services. This was a mechanism to mitigate the risk of double dispatch or conflicting price signals between wholesale and network support services.
Project EDGE. 2023, Project EDGE Bi-directional Offer (Boffer) for Wholesale Energy: Options for aggregators to participate in off-market wholesale dispatch – high level design document, p 9. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-technical-specifications

The current approach to NSS procurement in the UK and Australia[304] is the low standardisation point-to-point model. Generally, services are procured via direct agreements with commercial and industrial (C&I) customers through bilaterally negotiated contracts for targeted demand response that are firm and can be relied upon. Firm network support services are also procured from third parties, such as aggregators of DER or C&I demand response, through tenders and negotiated bilateral contracts.

While DNOs in the UK have been tendering and procuring NSS from DER in the UK since 2018, the energy regulator (Ofgem) and industry acknowledge areas for development. Ofgem identified that challenges around market access and coordination are preventing distributed flexibility from being able to fully offer and receive system value for these services[305] Ofgem proposes a 'common vision' for distributed flexibility and, specifically, a common digital infrastructure (discussed further in a case study in section 7.3.1).

Project EDGE explored the two models on the right in Figure 103 (Connected to DER data hub and Centralised) in the design phase, and then implemented the medium standardisation option (Connected to DER data hub) for the LSE in the field tests.

In the **Connected to DER data hub** model, DNSPs could design and operate (or outsource if preferred) an LSE solution, which is connected to the DER data hub to facilitate standardised data exchange. Project EDGE implemented this concept but did not develop a full LSE solution.

In the **Centralised** model, one LSE application would be facilitated by AEMO, with NSS characteristics defined in the solution so that DNSPs select which service characteristic they want to procure from a standardised list. From an aggregator perspective, the service characteristics and transaction method would be the same across any DNSPs utilising the centralised LSE. This approach was not tested in Project EDGE, for reasons outlined below.

The key advantages to the Connected to DER hub approach versus the Centralised approach are as follows:

- DNSPs can move at their own pace and have operational control over the services they procure and dispatch.
- AEMO can receive aggregated visibility of local NSS dispatches without any requirement to have a role in the trade of local NSS between DNSPs and aggregators.
- DNSPs can design services to meet their needs (within a standardised framework).

In Project EDGE, AusNet defined the services to be tested and appropriate channels were added to the data hub solution to exchange necessary signals to trigger arming/dispatch of the services and sharing of telemetry.

  - AusNet used smart meter data to verify service delivery. However, there were instances where AusNet sought aggregator telemetry data to further explain unexpected results.

In this model, there could be an LSE for each DNSP/region, and service standardisation could be achieved by aligning the design of each LSE to a guideline/framework agreed with industry on the five factors of network support services standardisation outlined in section 7.1: communicating needs, services definition, transaction terms, data exchange and user experience.

Connection to / integration with a DER data hub enables standardisation associated with identity and access management, consistent standing and portfolio management data, and the exchange of operational data.

A design for this model may also enable DNSPs to maintain data sovereignty for data associated with services trades in their LSE application, as with the EDA model in Austria.[306]

304 For example, CitiPower, PowerCor and United Energy in Victoria. Discussions with an aggregator also identified bilateral 'point to point' contracts for network support services exist with Energy Queensland.

305 Ofgem. 2023, The Future of Distributed Flexibility: Call for Input. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

306 EDA. https://www.eda.at/wie-funktioniert-eda?lang=en

7.3 Findings

This section summarises the key findings from the literature review and field trials relating to the design and trade of local NSS.

7.3.1 Literature review: UK consultation on distributed flexibility

The point-to-point approach would occur under status quo arrangements in Australia, whereby each DNSP could develop/procure its own digital solution to procure NSS at scale. This is the model that has been implemented so far in the UK.

Although UK distribution networks have developed independent flexibility markets that are tendering for GWs of distribution flexibility services, Ofgem (the UK energy rule maker and regulator) launched a consultation on the future of distributed flexibility stating a case for change was triggered by

"Significant issues around the pace of delivery; the often-limited Distribution Network Operator and Electricity System Operator coordination; high friction in market entry, burdensome processes, and lack of user-centric design."[307]

Ofgem identified 'market failures' that are restricting the ongoing growth of these services, including:

- Imperfect information and information asymmetries
- Limited coordination and standardisation creating a 'transactional burden for sellers that manifests as barriers to entry'
- A structural lack of trust, clear governance and/or market oversight means sellers don't believe markets are being operated impartially
- Barriers to entry relating to non-standardised requirements such as bespoke legal terms, high liability levels or specific metering needs.[308]

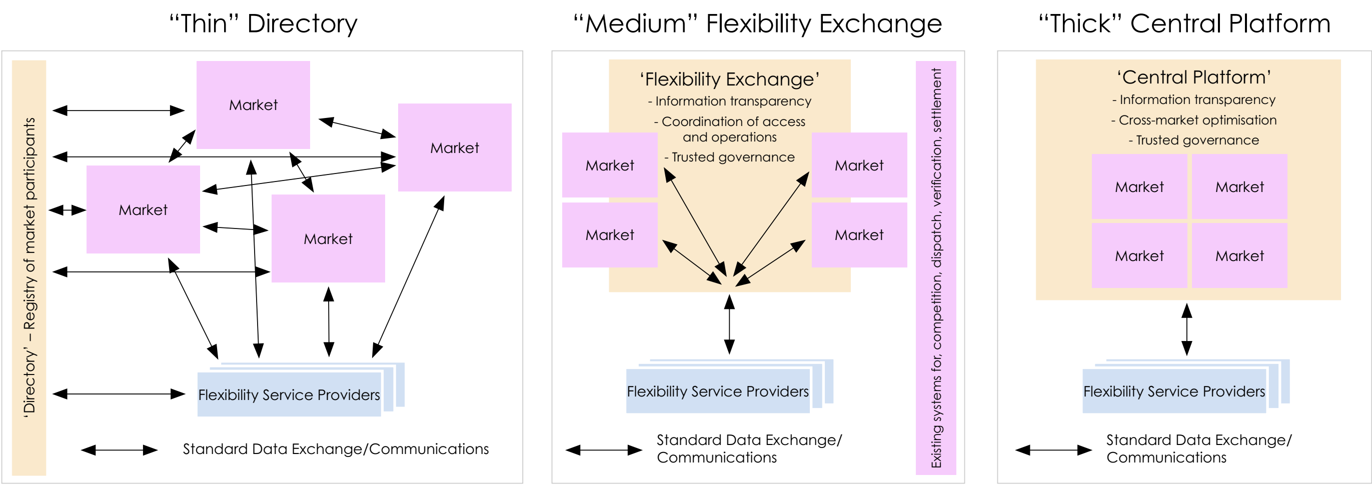
Although Australian DNSPs have not started procuring NSS at scale yet, the same market failures could occur under a point-to-point approach, possibly with the exception of the third market failure above as DNSPs have statutory obligations to remain impartial and consider NSS without bias.[309] However, this may still be a potential barrier in Australia if aggregators perceive the market isn't being operated impartially, which could limit the uptake of aggregators providing network support services.

Ofgem has proposed to implement a 'new common digital energy infrastructure' to help ensure:

- Information transparency
- Common access to and coordination across markets
- Suitable trust and governance arrangements on the trade of flexibility services.

Ofgem has proposed three models for facilitating the trade of distributed flexibility services through the 'new common digital energy infrastructure'. These models are shown in Figure 104.

Figure 104: Ofgem proposed technology models for new common digital energy infrastructure for distributed flexibility



Source: Ofgem, Call for Input: The Future of Distributed Flexibility[310]

Ofgem's assessment appeared to show the 'Medium Flexibility Exchange' model as the most favourable option, as outlined in their assessment framework shown in Figure 105.

Figure 105: Ofgem's assessment of current practice and three distributed flexibility technology models

	BaU - let distributed flexibility continue without intervention	Thin - a directory of protocols & standards	Medium - an exchange	Thick - a central platform
Information provision: services that enable greater visibility of market rules, product data and asset performance as well as external information, where appropriate.	**Very limited** - bilateral interactions don't give transparency	**Limited** - register of markets and assets available improves visibility, but bilateral interactions don't give transparency	**Good** - single source of truth for market and asset data including historic performance and basic analytics	**Good** - same as medium
Market coordination of operations and access: services that aim to improve operational efficiency and streamline various stages of the procurement processes.	**Limited** - multiple bilateral market interactions must be set up, no common access point/process	**Limited** - multiple bilateral market interactions must be set up, no common access point/process	**Good** - central coordination services to notify of bid/ dispatch conflicts, also common access point/ processes for some aspects	**Very good** - full co-optimisation across all markets and common access point/process for all aspects
Trust and governance: services that enable transparency in decision making and governance, fostering trust in the marketplace.	**Very limited** - no common governance role, limited decision making transparency	**Limited** - no substantial common governance role but register monitored for accuracy, limited decision making transparency	**Good** - governance of common platform services, disputes and change management, improved decision-making transparency	**Very good** - (depending on entity) - full central governance of all aspects, full decision-making transparency
Desirability – **Providing 3 functions**	**Very limited** - existing markets and bilateral interactions with limited provisions of functions	**Limited** - some improved visibility, but limited coordinated access or operations and limited role for governance	**Good** - single source of truth for information, services for market coordination and single point of access, governance for common services	**Good** - single source of truth for information and single point of operation and governance for all markets
Desirability – **User-centric design**	**Very limited** - high friction user experience finding and accessing the individual markets separately	**Very limited** - users have visibility of each other, but still need to access on an individual basis	**Good** - sellers can easily access multiple markets; buyers can easily coordinate across markets	**Good** - fully streamlines all steps for sellers and optimises market operation for buyers
Desirability – **Net-new functionality**	**N/A** - counterfactual	**Very limited** - provision of new common register	**Good** - provides multiple new functions, and does not duplicate existing functions	**Limited** - provides substantial new functionality but also overlaps existing functions
Feasibility – **Time and cost to deliver**	**N/A** - counterfactual	**Good** - new infrastructure is small, simple and discrete from existing operations, minimising time/cost to deliver	**Limited** - new infrastructure is sizable with some complex aspects, so will take moderate time/cost deliver	**Very limited** - new infrastructure is substantial with significant complexity, so will be significant time/ cost to deliver
Feasibility – **Low external dependency**	**N/A** - counterfactual	**Limited** - would benefit from external initiatives, but could deliver functionality without them competing	**Limited** - would benefit from external initiatives, but could deliver functionality without them completing	**Very limited** - reliant on external initiatives e.g., could not deliver full co-optimisation without substantial LV visibility
Feasibility – **Adaptable and enabling innovation**	**Very limited** - interventions could change direction, but would only have slow progress state to build on	**Good** - creates a foundation of standards and protocols and small infrastructure that could be expanded	**Good** - creates a foundation of standards and protocols, and common infrastructure that innovators can leverage	**Very limited** - creates a foundation of standards and protocols, but infrastructure is already all encompassing

Source: Ofgem, Call for Input: The Future of Distributed Flexibility.[311]

Ofgem also proposed to assign a market facilitation function to a single entity with sufficient expertise and capability to deliver more accessible, transparent and coordinated flexibility markets. Ofgem proposed that the single entity could be the Future System Operator (FSO, AEMO's equivalent in the UK), although Ofgem stated the FSO is not the only entity that could fill this role and that it is open to feedback on this issue.[312]

310 Ofgem. 2023. Call for Input: The Future of Distributed Flexibility. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

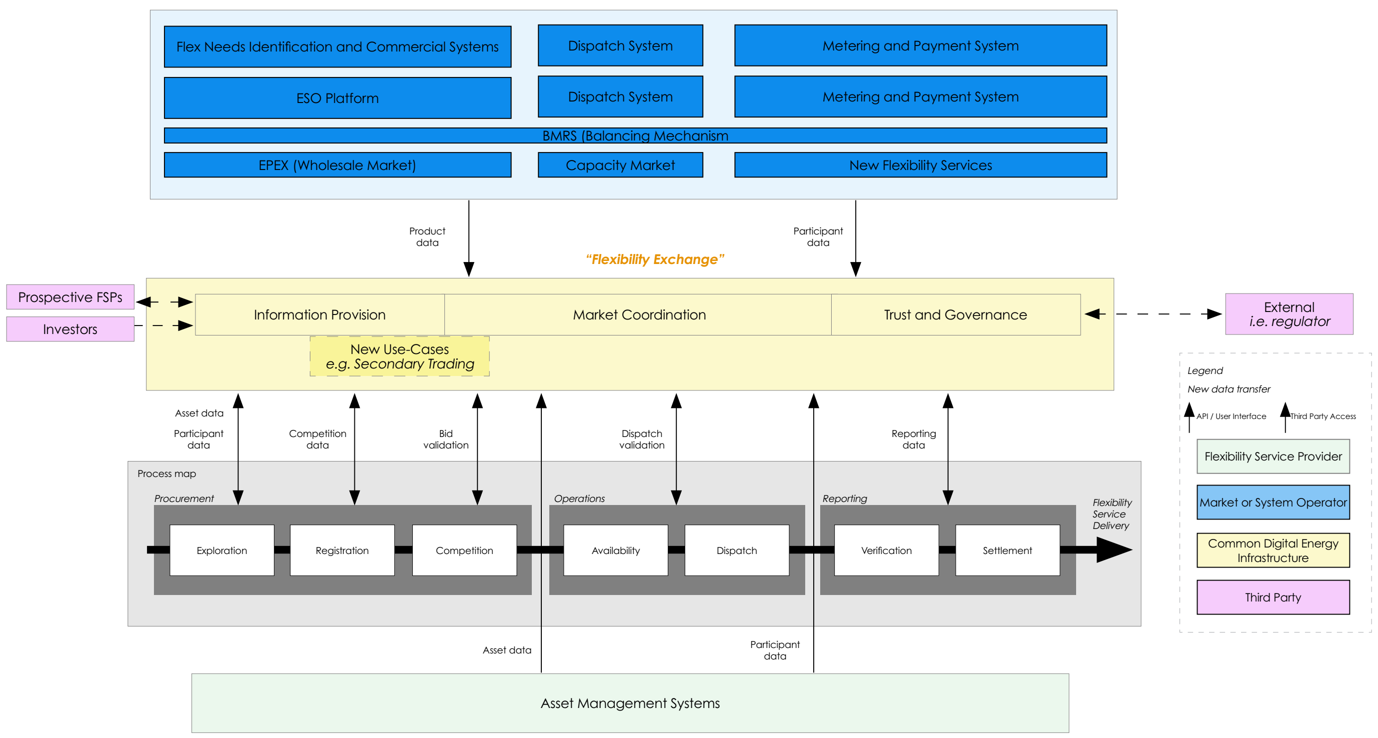
311 Ofgem. 2023. Call for Input: The Future of Distributed Flexibility. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

There are similarities between the models that Project EDGE has explored and the models proposed by Ofgem. The model for an LSE that Project EDGE tested (an LSE connected to a DER data hub) most closely aligns to Ofgem's 'Medium Flexibility Exchange' proposal in which different flexibility markets could be connected to 'common digital energy infrastructure'.

A key difference is that while Ofgem appears to lean towards the FSO (AEMO equivalent) as the entity responsible for operating/administering each distributed flexibility market in the exchange, Project EDGE tested a model whereby DNSPs could operate (or outsource if preferred) their own LSE/flexibility market.

The effectiveness of the Project EDGE approach at scale would depend on the level of standardisation achieved between each LSE/flexibility market. There may also be a case for Australian states with multiple DNSPs to have a single, state-based LSE/flexibility market that is operated by one of the DNSPs or outsourced to a third party (for example, see the case study on NODES in section 7.3.1)

Figure 106: Ofgem 'Medium Flexible exchange' model diagram in technical annex



Source: Ofgem, Call for Input: The Future of Distributed Flexibility.[313]

The literature review showed there is a spectrum of approaches to achieving standardisation in NSS trade. Experience with point-to-point approaches in the UK supports the case for standardisation and the use of a common data exchange mechanism to address issues around the scalability of NSS.

Australia has an opportunity to learn from the experiences in the UK and achieve a level of standardisation suitable for NEM participants before NSS trade scales up.

312 Ofgem. 2023. Call for Input: The Future of Distributed Flexibility p 52. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

313 Ofgem. 2023. Call for Input: The Future of Distributed Flexibility. https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility https://www.ofgem.gov.uk/publications/call-input-future-distributed-flexibility

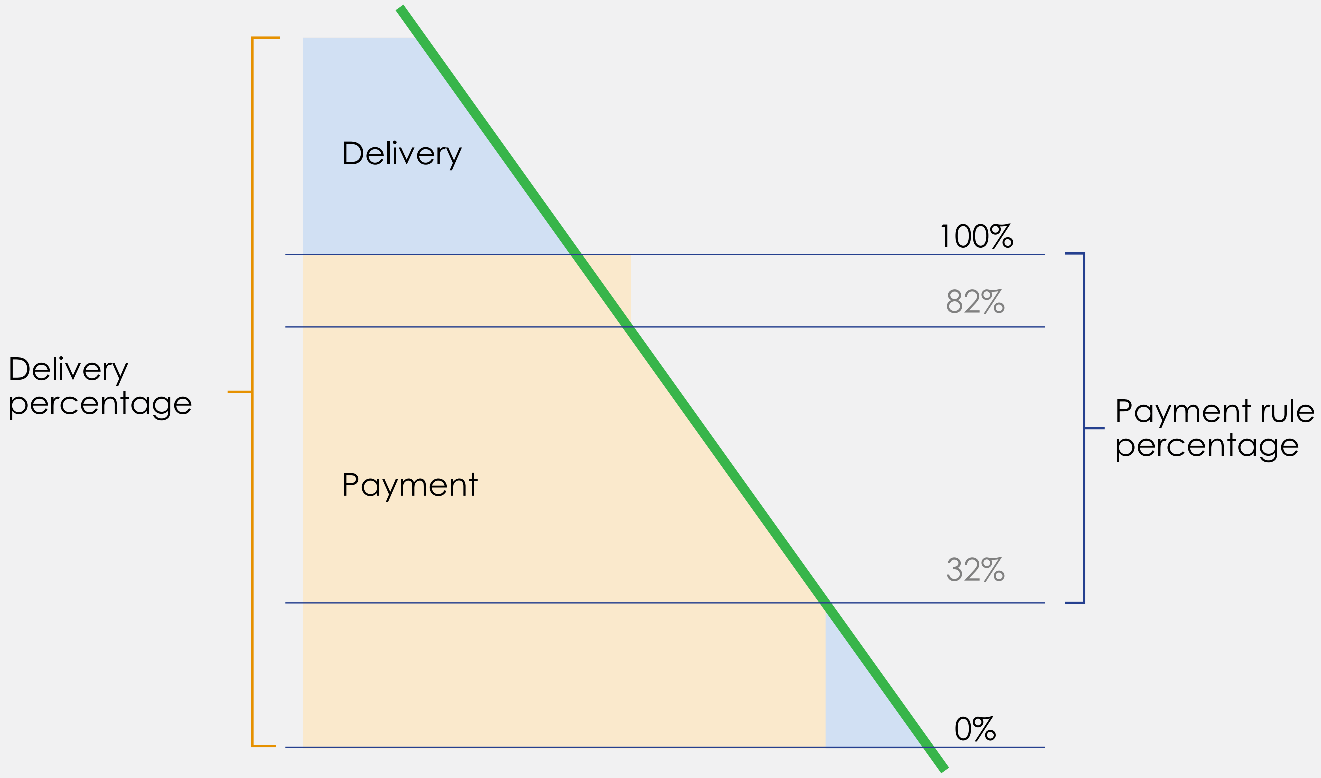
CASE STUDY

NODES

NODES is an independent operator of flexibility markets in Europe, including IntraFlex where Western Power Distribution (UK) outsourced the operation of a flexibility market to NODES,[314] and Norflex in Norway.[315] NODES administers these markets, acts as an intermediary between buyers (distribution networks) and sellers (aggregators), and also acts as a clearing house to process settlements.

An interesting feature of the Norflex market is that payment rules are based on a sliding scale against the delivery percentage, as shown in the figure below.[316]

Figure 107: NODES Norflex payment rules and delivery percentage (blue area represents no payment)



The assessment of delivery uses meter data submitted by the seller into the DSO's Asset Hub (a data portal that each DSO establishes and enables access for service providers and NODES) covering a minimum of two hours before and two hours after the activated period. NODES uses this data to validate delivery and the payment rules determine how much is paid to the seller.

Norflex does not implement a penalty for under-delivery, only reduction of payment. In some NODES

314 In the UK, the flexibility markets primarily include larger DER connected to the medium voltage network. As such, their baselining approach and response to signals could be significantly different to the LSE fleets that participated in Project EDGE, comprising DER connected to the LV network. As such, this case is used to illustrate an example of a market for services rather as a specific example of DER providing LV network services for demand management.

315 NODES 2023. Flexibility. https://nodesmarket.com/flexibility/

316 CIRED. 2022. Norflex: Accommodating e-mobility in the distribution grid. Utilising a flexibility^ market to manage grid congestion. https://nodesmarket.com/publications/

applications in the UK, consistent underperformance is managed through the aggregator being disqualified from providing certain services, limiting compliance and enforcement overheads for DNOs.[317]

The Norflex example also reflected on the current practice of each DSO developing their own Asset Hub to support data exchange.

"Developing a custom solution for each market would limit the expansion of aggregators and impair the use of those assets. An ideal solution would be to have one platform at a country level."[318]

7.3.2 Field trials and results

DER can deliver firm network services and value stack with wholesale services

Project EDGE tested five network support services, with:

- Demand increase, high firmness
- Demand decrease, high firmness
- Demand increase, low firmness
- Demand decrease, low firmness
- Voltage, high firmness.

The characteristics were designed and defined by AusNet as shown in Table 20.

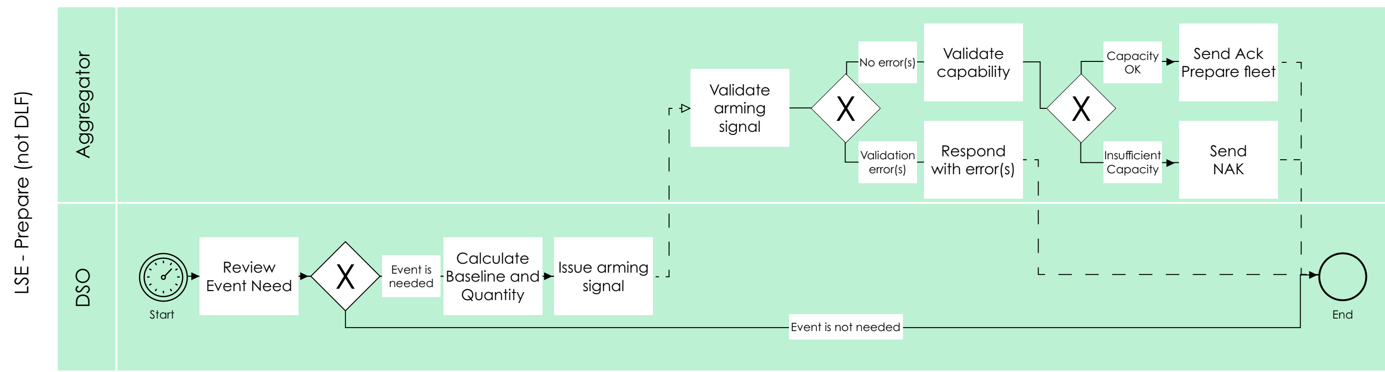
Table 20: Key characteristics used to define local network support services in Project EDGE

Characteristic	Description	Demand increase or decrease high firmness	Demand increase or decrease low firmness	Voltage management high firmness
Power	Active or reactive	Active	Active	Reactive
Location	Location of service delivery	Zone substation, feeder, LV distribution, phase, circuit	Zone substation, feeder, LV distribution, phase, circuit	At NMI (or collection of NMIs) level
Payment type (availability)	Customer is paid to be available during a particular timeframe	$/kW (contractually fixed)	N/A	$/kVAr (contractually fixed)
Pricing (performance)	If the customer is activated or dispatched, payment is made based on performance (verified delivery of real power)	N/A	$/kWh (negotiated per posted need)	N/A
Contract duration	Length of contract between DNSP and aggregator	12-24 months	3 months (seasonal)	12-24 months
Number of activations	How many times a DNSP can engage an aggregator	Min and max	No min or max (all activations are negotiated)	Unlimited
	Min – aggregator gets paid for these activations regardless Max – aggregator cannot be called more often than this			
Arming signal timing	Time of signal to prepare	2 days (high firmness)	No arming signal for low firmness	N/A – local detection
Service start trigger	Marks start of activation period and signal	Date and time Trigger – dispatch signal	Date and time Trigger – dispatch signal	Date and time Trigger - start and end date/time of applying tighter Volt-VAr curve. The service operates between those times, though the inverters locally detect voltage excursions.
Service end	Marks end of activation	Date and time	Date and time	Date and time

The field testing of delivery of the five network support services tested in Project EDGE was referred to as an 'LSE event'. The event included a preparation period – the period after which the aggregator received an arming signal from the DNSPs alerting the aggregator to begin preparing its LSE portfolio for the service. This was followed by a service start trigger (notice signal) that signalled to the aggregator the impending start of the activation of the service.

Figure 108 and Figure 109 illustrate the high-level process applied in Project EDGE for the preparation and delivery of an LSE event.[319]

Figure 108: High-level process map of preparation for a demand increase or decrease high firmness LSE event



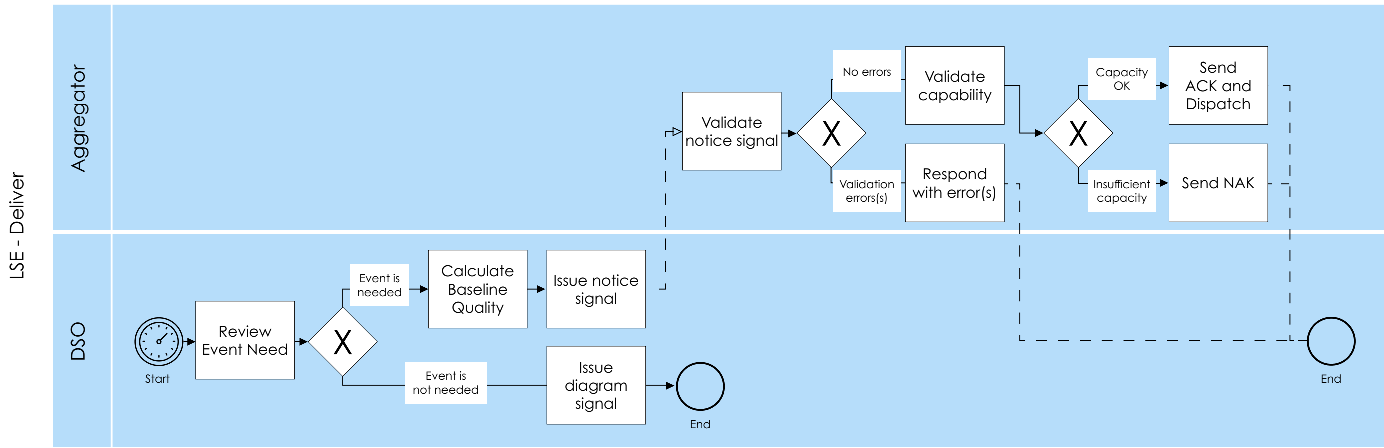
317 NODES. Project EDGE Interview.

318 CIRED. 2022. Norflex: Accommodating e-mobility in the distribution grid. Utilising a flexibility^ market to manage grid congestion. https://nodesmarket.com/publications/

319 Additional and more detailed process maps are published in Chapter 3.

Project EDGE. 2023. Project EDGE High Level Design: Local Services Exchange (LSE). https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge---local-service-exchange-hld.pdf?la=en

Figure 109: High-level process map of delivery for an LSE event



Note: Delivery occurs alongside wholesale market activities and is incorporated through the bids and offers, dispatch instructions, and dispatch activities (see section 5.3.2.9).

The approaches to evaluating the delivery of the service, and definition of key terms and metrics, are outlined in the following sections.

7.3.2.1 Approach to determining quantities for services

In Project EDGE, the approach to determine quantities included the DNSP:

- Reviewing forecast conditions and determining the actions needed to alleviate the situation. This would inform the baseline and the quantity determination
- Considering the available aggregator(s) and determining a baseline and quantity for the LSE-registered assets that were contractually available for each aggregator.

The baseline is the seasonal (e.g. spring) contractual baseline, being the average load/generation over time. The baseline determines the target (for high firmness services). It reflects the quantity an aggregator's LSE portfolio could deliver.

An aggregator's LSE portfolio would be a 'sub' portfolio within its entire DER portfolio. This is because LSE events are required to meet local network constraints. As such, it requires services from NMIs located within the constrained network area. This means an aggregator could have multiple LSE portfolios, each comprising a group of NMIs within the same local network area.

The baseline would be calculated according to an agreed contractual methodology. When an aggregator adds or removes DER from its LSE portfolio, the baseline would need to be recalculated.

A baseline profile is a range of data points for the baseline throughout the activation period, where the starting point for the increase or decrease changes. While AusNet calculated these profiles throughout the trial, AusNet only asked the aggregator to use a constant baseline as the starting point. Using baseline profiles was identified as a potential future improvement.

The LSE portfolio event baseline profile reflects the more recent historical power use profile for an aggregator's LSE portfolio for the specific event time period (e.g. the historical power use profile between 16:00 and 19:00).

7.3.2.2 Approach to delivering a demand increase service

For a demand increase service, the aggregator must aim to get the total LSE-assigned NMIs in its portfolio in the affected network location(s) down to at least a demand of (baseline + quantity) and at most a demand of (baseline + quantity + range limit) where:

- The baseline is the average load/generation over time.
- Quantity is the required adjustment to satisfy demand increase/decrease.
- The range limit is specified in the contract terms and conditions (e.g. 30% below).

Generation is a negative load and demand increase can be performed by increasing actual loads consumed at the NMIs in the LSE portfolio or by decreasing generation at the NMIs in the LSE portfolio.

On an arming signal, the LSE portfolio must prepare to be able to increase load (or reduce generation) so that the (baseline + quantity) target is met. This must also be accounted for in the wholesale bi-directional offer.

On a notice signal, the LSE portfolio must increase load or reduce generation to get the total consumption above (baseline + quantity) for the period of the LSE event.

7.3.2.3 Approach to delivering a demand decrease service

For a demand decrease service, the aggregator must aim to get the total LSE-assigned NMIs from its portfolio in the affected network location(s) down to at least a demand of (baseline – quantity), and at most a demand of (baseline – quantity – range limit) where.

- The baseline is the average load/generation over time.
- Quantity is the required adjustment to satisfy demand increase/decrease.
- The range limit is specified in the contract terms and conditions (e.g. 30% below).

Generation is a negative load and demand decrease can be performed by decreasing actual loads consumed at the NMIs in the LSE portfolio or by increasing generation at the NMIs in the LSE portfolio.

On an arming signal, the LSE portfolio must prepare and be able to decrease load (or increase generation) so that the (baseline-quantity) target is met. This must also be accounted for in the wholesale bi-directional offer.

On a notice signal, the LSE portfolio must reduce load or generate to get the total consumption below (baseline-quantity) for the period of the LSE event.

7.3.2.4 Approach to verification and payment of service delivery

Initially, the DNSP and the aggregator independently analysed the data and results from each LSE event to evaluate performance and assess the aggregator's delivery compliance. This was followed by a collaborative discussion to compare data analysis results and provide additional context associated with the aggregator's delivery and identify key insights.

High firmness

Demand services are defined by price, volume, timing and duration. Project EDGE did not include pricing.

Volume

Performance is assessed on whether the aggregator's LSE portfolio consistently meets the target. The baseline acts as the safeguard; during an event, the aggregator cannot deliver less than the baseline. Meanwhile, the event target represents the peak quantity that cannot be exceeded.

High firmness contracts would have an annual quantity cap. Once that cap is reached, the DNSP could either stop calling on that aggregator or there could be a contractual clause on how payment would be made for deliver services. The DNSP could also call upon the aggregator for low firmness events.

The step change to target was defined and evaluated at the Net NMI point, not on the controllable devices. All network support services would be measured at Net NMI because these services are attempting to address constraints upstream in the network. From an aggregator perspective, this means it would need to manage any uncontrolled load behaviour that could impact net delivery of the target. If it did not, it would result in unsuccessful delivery of the LSE service.

Timing and duration

In Project EDGE, high firmness events were always tested for 3 hours during times there would typically be a need to manage peak demand or manage minimum load.

The NMIs participating in Project EDGE were not located in a network constrained area; therefore, there were no actual network constraints that needed to be managed during those times. The objective of the tests was therefore to assess whether the aggregators have the technical capabilities to deliver services for theoretical constraints.

Three hours was selected driven by (theoretical) network requirements. To manage peak demand or minimum load effectively, the network would need 3 hours because such events occur for several hours.

Performance was also based on whether the aggregator was able to deliver to the target consistently, during the notified event times and for the entire duration of the event. The reason for the consistent duration requirement is because the intent is to alleviate constraints on the transfer, which requires consistent performance. For example, a demand decrease service would be called so as not to overload the transformer from maximum demand pressures. The transformer can withstand being overloaded intermittently for a few minutes for the duration of the event and the DNSP has a general thermal capacity to allow for this in terms of overload. However, if it is overloaded consistently for longer periods (e.g. 15-30 minutes), this could cause technical issues for the transformer.

Performance and compliance metrics

In Project EDGE, the DNSP applied two metrics. It used aggregated 5-minute power quality (PQ) data and 30-minute interval data from the LSE portfolio's smart meters. From these two measures, the DNSP calculated two metrics:

- Event compliance used PQ data to determine consistent compliance throughout the event duration
- Event performance used the energy interval data to evaluate whether the aggregator responded to the quantity required for the event duration.

This data is obtained from smart meters, which is a DNSP asset in Victoria where the field trial took place. Smart meter data was chosen by the DNSP to verify service delivery rather than aggregator telemetry because it provided an independent verification. Additionally, it was data directly available to the DNSP.

Both energy interval data and PQ data were used because using only one or the other may not provide an accurate determination of whether the service was delivered successfully. For example, the 30-minute energy interval data provides the exact kWh energy flow during the event, but it does not provide the shape in which that energy flow varied within that time.

The challenge for the DNSP with the 30-minute interval data is that energy flow could go over and under the target, but the average meets the target. As noted, depending on the duration of the periods during which delivery is under or over, the service may not alleviate constraints.

Meanwhile, the 5-minute PQ data provide the shape of energy flow but not exactly how much energy was used/generated because it is a 5-minute snapshot that does not provide visibility of what occurred in between.

Together, the two measures provided the DNSP with a view of how delivery was achieved and whether it was able to alleviate constraints adequately.

There were instances with demand increase or decrease services where the analysis required communication with the aggregator to verify performance. In these scenarios, the DNSP requested aggregator telemetry. However, the DNSP generally adopted a position of using the data directly available to it.

In Project EDGE, for a high firmness service, a 90% compliance threshold was set. This meant a single instantaneous measure outside the 90% threshold would result in a service failure. However, as discussed in section 7.3.3, this may require further consideration by DNSPs.

To meet the 90% compliance threshold, the aggregator found it had to 'overshoot' and include a buffer in the quantity it delivered to account for inevitable peaks and dips in its delivery (implying higher costs for the additional quantity margin). A lower metric threshold would mean the aggregator could consider including a lower buffer. This would mean less costs to deliver for the aggregator.

Payment

For high firmness services, the aggregator would be paid for being available and participating for the service. The aggregator would not be paid for the actual kW (volume) delivered. The baseline acts as the safeguard; during an event, the aggregator cannot deliver less than the baseline. Meanwhile, the event target represents the peak quantity that cannot be exceeded.

High firmness contracts would have an annual quantity cap. Once that cap is reached, the DNSP could either stop calling on that aggregator, or there could be a contractual clause on how payment would be made for deliver services. The DNSP could also call upon the aggregator for low firmness events.

Under this approach, the aggregator would get paid a set, regular amount (e.g. on a monthly basis). This means the aggregator would get paid by the DNSP even if it did not meet the target and successfully deliver the services. However, under such a scenario, it would trigger a contractual penalty (e.g. a claw back if the target was not met).

Low firmness

Volume, timing and duration

For low firmness service, there is no guarantee the aggregator will be able to deliver the service. Accordingly, the aggregator would not be penalised for non-compliance if it was unable to deliver. The aggregator was assessed on the maximum export/import it could provide for as long as it could provide it at the time it was activated, rather than a set target for the duration of the event. The aggregator would be paid for how much it delivers rather than how much is available (noting no payments were made in the project).

In Project EDGE, the verification maintained a target quantity and duration of 3 hours, and applied the same verification metrics to low firmness services as applied to high firmness services. However, meeting the target and the metrics are not relevant to low firmness services (since the aggregator is required to provide as much as it can for as long as it can).

Ideally, the DNSP would want an aggregator to deliver as much as it can over 3 hours; however, this did not impact the conformance evaluation. These metrics were maintained as an artefact of the structure and process to assess high firmness but did not determine whether the aggregator was considered to have successfully delivered the service.

Voltage management

For voltage services, the service involved applying tighter Volt-VAr (VAr is the measuring unit for reactive power) curves for a length of time. Voltage can be managed via a Volt-VAr curve. It is either an injection or absorption of reactive power.

The combination of a configurable array of points define a linear curve that results in the desired Volt-VAr behaviour. The special curves must be set into the DER devices at the start of the event period. At the end of the event period, the devices should revert to the standard curve. The aggregator was evaluated on whether its performance followed the curve.

The service request was an inverter level request; however, the conformance was measured at the site. The site loads influence reactive power, so the measurement needed to align with the request. It is possible to request a site level reactive target, but this was not tested in the project.

For voltage management services, the DNSP would need aggregator telemetry to verify performance. This is because voltage management performance is achieved through scheduling Volt-VAr settings into individual inverters.

The aggregator was evaluated on whether its performance generally followed the curve rather than whether it exactly matched the array of points in the curve.

The DNSP would not have access to the inverter data to verify performance. Smart meter data would observe strict compliance with performance along the Volt-VAr curves for a length of time.

Example results from aggregator performance in delivering the services tested are discussed below. The key learnings and insights from these examples and all other LSE events completed are synthesised in the following case studies.

CASE STUDY

Demand increase, high firmness event performance and results

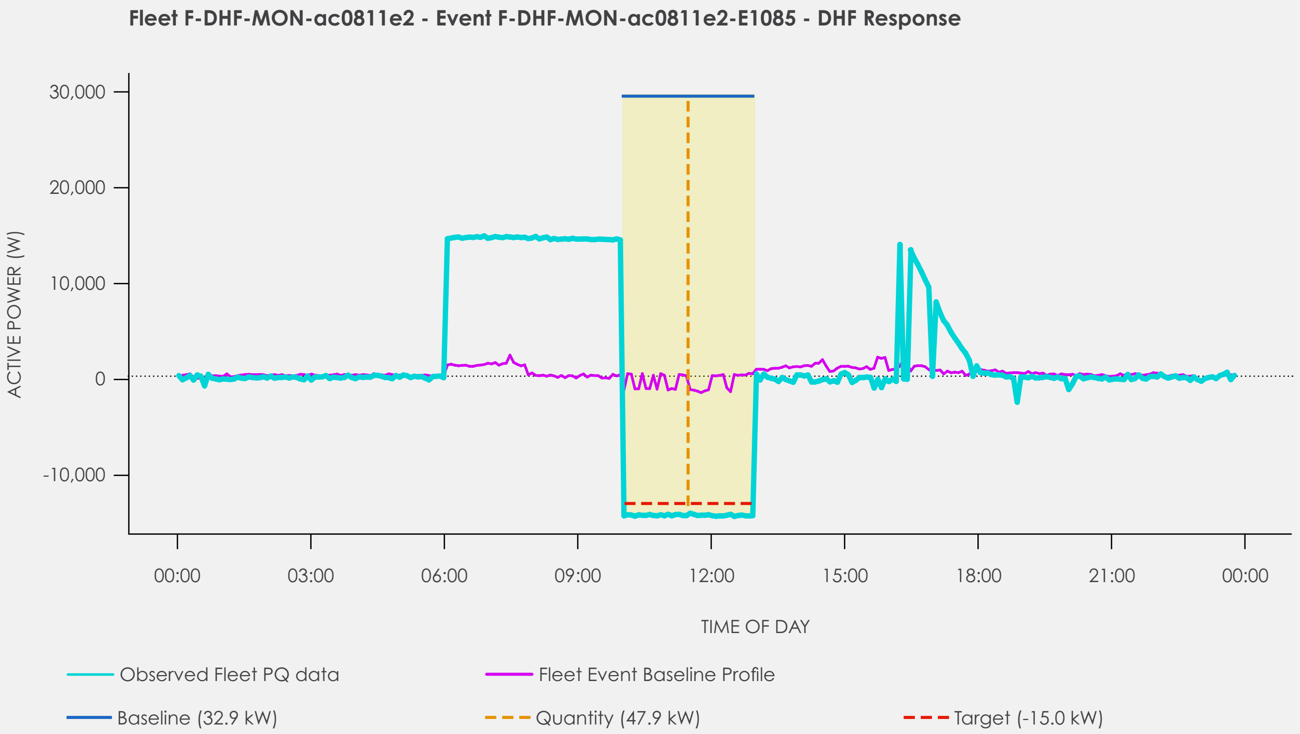
In general, for demand increase, high firmness services, the aggregator would prepare and deliver in the following ways (depending on the LSE portfolio):

- Depending on the state of charge, the aggregator may need to empty the battery to prepare.
  - The aggregator noted that customers noticed this unusual behaviour and as such, education on VPP activity would be required.
- Service is delivered by charging the battery from the grid, to increase demand.
  - Turning on controlled loads is also an option, but may be more difficult to forecast and commit if devices consume variable power.
- Solar may also be curtailed to further increase demand
  - This was only used if required.

Figure 110 provides an example of a demand increase, high firmness event that occurred on a weekend in summer, and for which the aggregator was evaluated as having delivered the service successfully. The weather forecast was sunny and hot (31.30C). The event occurred from 10:00 until 13:00 (EST). The demand increase target was 15kW[320] for a duration of 3 hours from 10:00 to 13:00 (EST).

320 As noted in section 2.3.2.4, the aggregator would be paid for being available and participating for the service and not the actual kW. The target represents the peak quantity for the event that cannot be exceeded (and for a firm service, it is the quantity that must be delivered consistently for the duration of the event period. If the aggregator did not meet the target, it would be paid regardless. However, the contract would have a claw-back clause for such scenarios.

Figure 110: Demand increase, high firmness event (11th February 2023) verification conducted by the DNSP



PERFORMANCE METRICS		
Metric	Result (Interval Energy Data)	Result (Power Quality Data)
Event Compliance (%)	100.0	100.0
Event Performance (%)	100.0	100.0

At the beginning of the preparation period, the battery[321] was at 50% state of charge. To prepare for the event, the aggregator discharged the LSE portfolio battery between 06:00 and 09:30 hours to free up import capacity and then charged it to meet the event need.

The cream shaded area represents the LSE event period. The purple line reflects the LSE portfolio's baseline profile. The red dashed line reflects the import target required to meet delivery compliance for the event. The blue line reflects the observed LSE portfolio power quality (PQ) data.

The results show the blue line (observed LSE portfolio PQ data) was better than the demand increase target. Accordingly, the DNSP evaluated and verified the aggregator was able to achieve performance and compliance for the entirety of the event duration.

321 This particular LSE portfolio comprised a single NMI and battery.

CASE STUDY

Demand decrease, high firmness event performance and results

In general, for demand decrease, high firmness services, the aggregator would prepare and deliver in the following ways (depending on the LSE portfolio):

- The aggregator would generally seek to turn-off controllable loads. However this was not tested in Project EDGE by the aggregators.
- In the project, the aggregator charged batteries to prepare for delivery.
- During delivery, sites were powered by battery to reduce site demand.
  - An extreme demand reduction may require sites to export from battery discharge.
- These services were required in the evening when there was no solar.

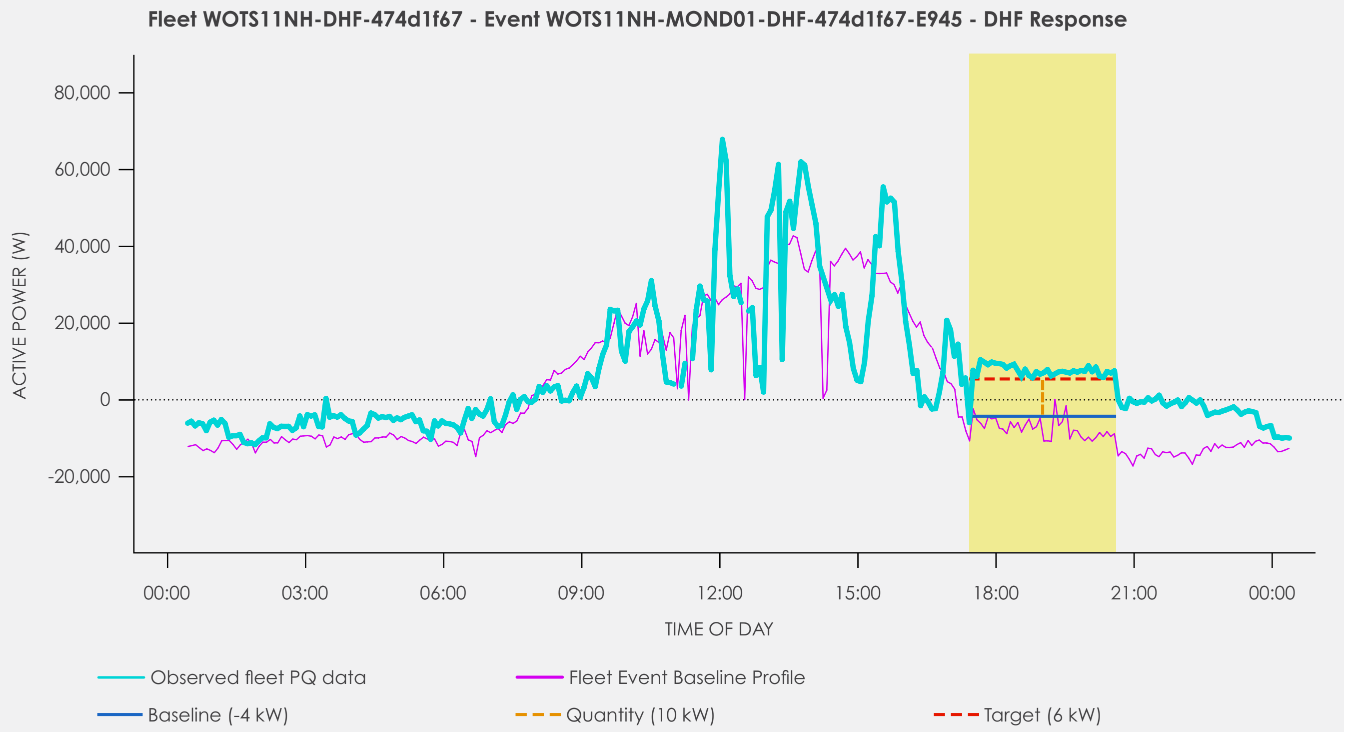
Figure 111 provides an example of a demand decrease, high firmness event that occurred on a weekday in summer and for which the aggregator was evaluated as having delivered the service successfully. The weather forecast was partly cloudy and warm (29.50C). The event occurred from 17:00 until 20:00 (EST). The demand decrease target was 6kW for a duration of 3 hours from 17:00 to 20:00 (EST).

When the aggregator received the arming signal, the LSE portfolio batteries were already at a high state of charge primarily from rooftop solar generation earlier in the day and had all reached high state of charge limits during the LSE portfolio preparation period.

The battery[322] of the LSE portfolio was at maximum state of charge at the beginning of the activation window as a result of favourable solar weather and preparation scheduling earlier in the day.

322 This particular LSE portfolio comprised a single NMI and battery.

Figure 111: Demand decrease, high firmness (24th January) verification conducted by the DNSP



PERFORMANCE METRICS		
Metric	Result (Interval Energy Data)	Result (Power Quality Data)
Event Compliance (%)	100.0	100.0
Event Performance (%)	100.0	100.0

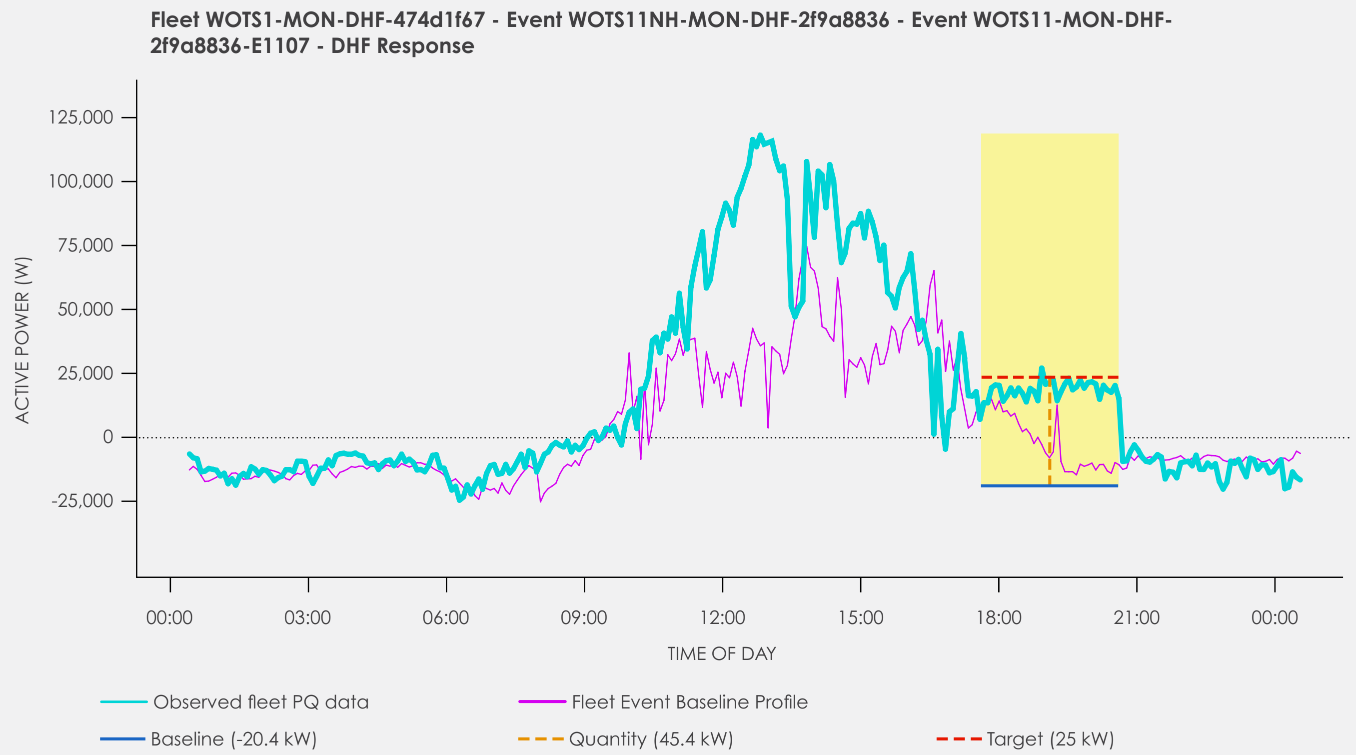
The cream shaded area represents the LSE event period. The purple line reflects the LSE portfolio's baseline profile. The red dashed line reflects the demand decrease target required to meet delivery compliance for the event. The blue line reflects the observed LSE portfolio power quality (PQ) data.

The results show the blue line (observed LSE portfolio PQ data) has exceeded (over-delivered) the target. Accordingly, the DNSP evaluated and verified the aggregator was able to achieve performance and compliance for the entirety of the event duration.

Figure 112 provides an example of a demand decrease, high firmness event that occurred on a weekday in summer, and for which the aggregator was evaluated as having failed to deliver the service. The weather forecast was sunny and warm (27.90C). The event occurred from 17:00 until 20:00 (EST). The demand decrease target was 25kW for duration of 3 hours from 17:00 to 20:00.

The battery of the LSE portfolio was at maximum state of charge at the beginning of the activation window as a result of favourable solar weather and preparation scheduling earlier in the day.

Figure 112: Demand decrease, high firmness event (13th February 2023) verification conducted by the DNSP



PERFORMANCE METRICS		
Metric	Result (Interval Energy Data)	Result (Power Quality Data)
Event Compliance (%)	56.93	1.71
Event Performance (%)	89.36	89.31

The cream shaded area represents the LSE event period. The purple line reflects the LSE portfolio's baseline profile. The red dashed line reflects the demand decrease target required to meet delivery compliance for the event. The blue line reflects the observed LSE portfolio power quality (PQ) data.

The results show the blue line (observed LSE portfolio PQ data) is below the target value a majority of the time. Accordingly, the DNSP evaluated and verified the aggregator was close but consistently below target and failed to deliver the service.

The proximity to target is highlighted by the high event performance percentage; the delivery consistently below target is highlighted by the low event compliance percentage. As discussed in section 7.3.2.4, delivery consistently below target would not help the network alleviate the constraint. Intermittent and short instances of delivery being over or under target could be tolerated by the DNSP. However, persistent and longer durations (e.g. 15-30 minutes) would not help alleviate overloading of the transformer and could cause technical issues.

CASE STUDY

Demand increase, low firmness event performance and results

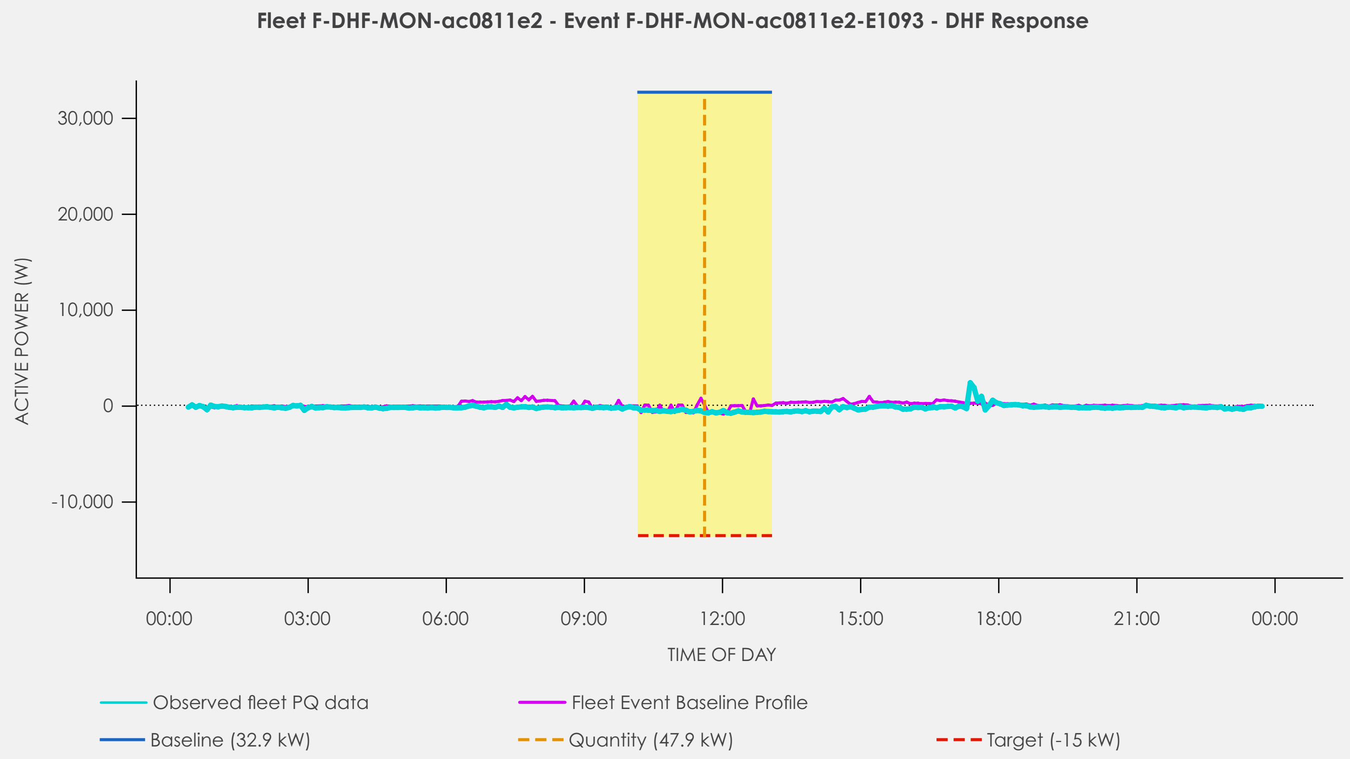
Low firmness services did not include preparation because the aggregator is required to provide as much as they can for as long as they can. Accordingly, the aggregator generally followed the below approach to deliver the service:

- The service was delivered by commanding maximum import (turn-off solar and maximum charge the battery) and maximum export (maximum discharge of battery).
- The service ran as long as possible within the agreed window.
- No preparation was required, as the service requests aligned with times that the batteries were in a suitable state.
- There was no target for these services, although the request included a value (that was ignored) for consistency.
- All of the solar was limited during the low firmness events.

Figure 113 provides an example of a demand increase, low firmness event that occurred on a weekend in summer, and for which the aggregator was evaluated as having delivered the service unsuccessfully. The weather forecast was sunny and warm (25.1°C). The event occurred from 11:00 until 14:00 (EST). The demand increase target was maximum available for as long as possible (and if possible, for a duration of 3 hours from 10:00 to 13:00 (EST)).

The battery of the LSE portfolio was at 90% state of charge at the beginning of the activation window from solar generation during the morning. During the event time window, the battery was only able to slow charge (to 10% maximum charge rate) as a result of the battery already being at a high state of charge.

Figure 113: Demand increase, low firmness event (12th February 2023) verification conducted by the DNSP



PERFORMANCE METRICS

Metric	Result (Interval Energy Data)	Result (Power Quality Data)
Event Compliance (%)	17.16%	0.0%
Event Performance (%)	70.29%	70.76%

The cream shaded area represents the LSE event period. The purple line reflects the LSE portfolio's baseline profile. The red dashed line reflects the demand decrease target for the event. The blue line reflects the observed LSE portfolio power quality (PQ) data.

The results show the blue line (observed LSE portfolio PQ data) did not reach the maximum target value. There was little room for the aggregator to provide the service due to the already high state of charge of the LSE portfolio batteries and lack of prior preparation time.

As noted above, for a low firmness event, the aggregator is required to provide as much as possible for as long as possible rather than a set target for the duration of the event. Accordingly, the compliance metrics in terms of performance and compliance percentage are not relevant for the verification assessment (and were applied by the DNSP as a template artefact within its systems for high firmness verification).

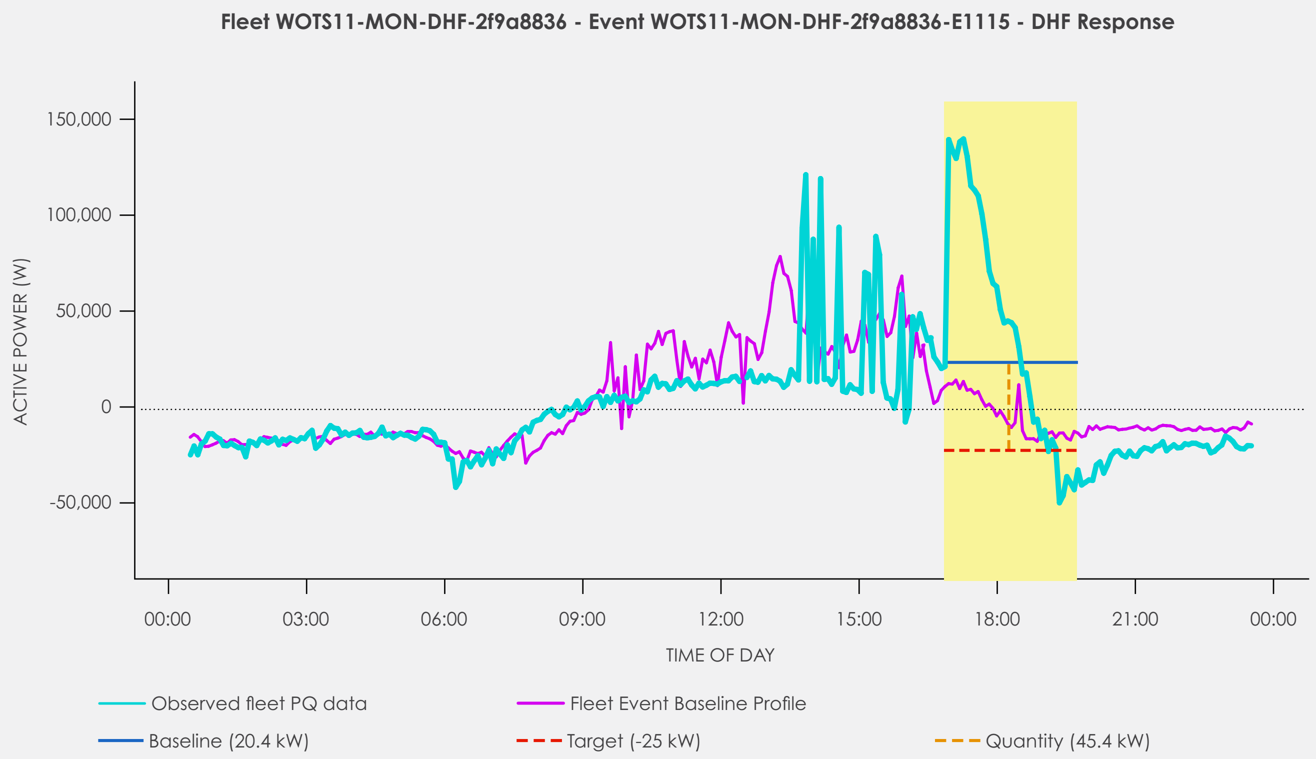
However, in this scenario, because the LSE portfolio battery was already at a high state of charge, the aggregator was not able to deliver any service to help alleviate the constraint. The aggregator increased demand as much as possible; however, without fleet preparation (which is not possible with low firmness services) there was limited impact of delivering the service.

CASE STUDY

Demand decrease, low firmness event performance and results

Figure 114 provides an example of a demand decrease, low firmness event that occurred on a weekday in summer, and for which the aggregator was evaluated as having delivered the service successfully. The weather forecast was sunny and warm (27.90C). The event occurred from 18:00 until 21:00 (EST). The demand decrease target was maximum available for as long as possible (and if possible, a duration of 3 hours from 17:00 to 20:00 (EST)).

Figure 114: Demand decrease, low firmness event (14th February 2023) verification conducted by the DNSP



PERFORMANCE METRICS		
Metric	Result (Interval Energy Data)	Result (Power Quality Data)
Event Compliance (%)	0.0%	0.0%
Event Performance (%)	64.28%	70.09%

The cream shaded area represents the LSE event period. The purple line reflects the LSE portfolio's baseline profile. The red dashed line reflects the demand decrease target required to meet delivery compliance for the event (noting for low firmness service where the target was stated to be the maximum available, the aggregator is evaluated on the maximum it can provide for as long as it can provide it rather than a set target for the duration of the event). Accordingly, the metrics in terms of performance and compliance percentage shown in the figure are not relevant compared with a high firmness event. The blue line reflects the observed LSE portfolio PQ data.

The results show the aggregator responded to the maximum target (the blue line (observed LSE portfolio PQ data) hitting the red dashed line). The batteries depleted within the 1 to 1.5 hour mark. Noting that the aggregator was not evaluated on whether it reached the target, in this instance, the aggregator's response happened to exceed the maximum target, but this was a coincidence rather than an intentional result. Because it was able to provide as much as it could for as long as it could within the event timeframes, the aggregator was assessed as having successfully delivered the service.

7.3.2.5 Voltage management, high firmness

The voltage management service comprises the application of Volt-VAr response curves at the customers' inverters over a specified time period. While an LSE portfolio providing voltage management services could comprise multiple sites, verification of delivery assesses each individual sites/NMI independently. This is because each site needs to be set to the Volt-VAr curve.

The voltage management event compliance was determined using the smart meter PQ data. As such, it is not a direct measurement at the inverter terminals. Accordingly, the measurement incorporates impacts of other appliances downstream of the point of connection. Therefore, event performance metrics were designed to discount the impacts of these appliances on the performance outcome as far as practicable.

This was done by assessing the shape of the response (i.e. whether there was alignment to the shape of the curve rather than strict compliance, which would require all points measured to align exactly with the points on the Volt-VAr curve). Because voltage management services require scheduling the Volt-VAr curve on each inverter, it is a set and forget mechanism. This means the aggregator cannot counter any load changes. As a result, this means some points will not align.

The results make references to various Volt-VAr curve definitions. They are defined by a curve ID (1, 2, 3, 4). When reading the results, the IDs correspond to the following Volt-VAr curve definitions. For reference, Figure 115 shows a sample Volt-VAr curve, depicting the inactive and active regions (V1 through to V4).

Figure 115: Volt-VAr control setting curve

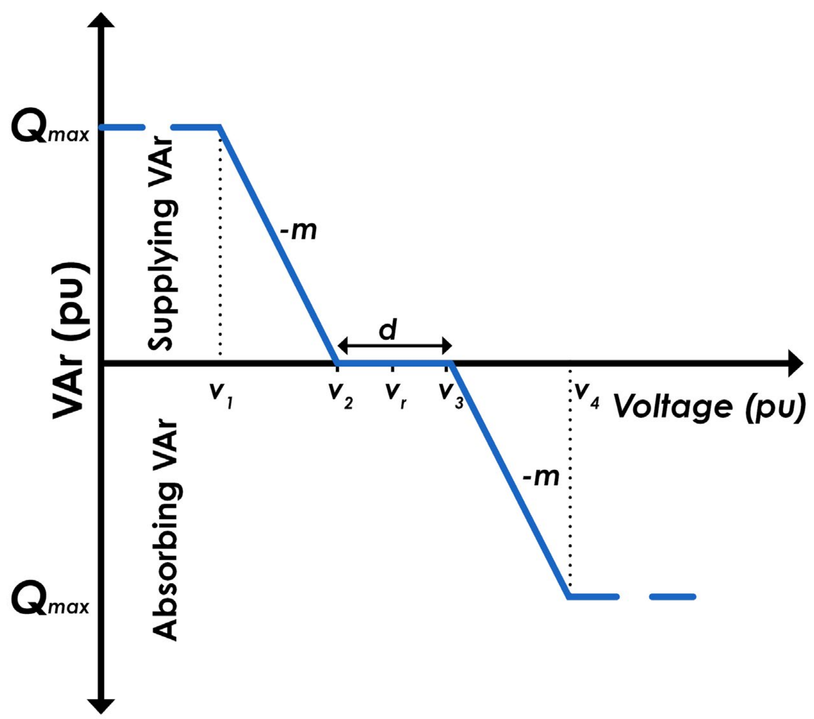


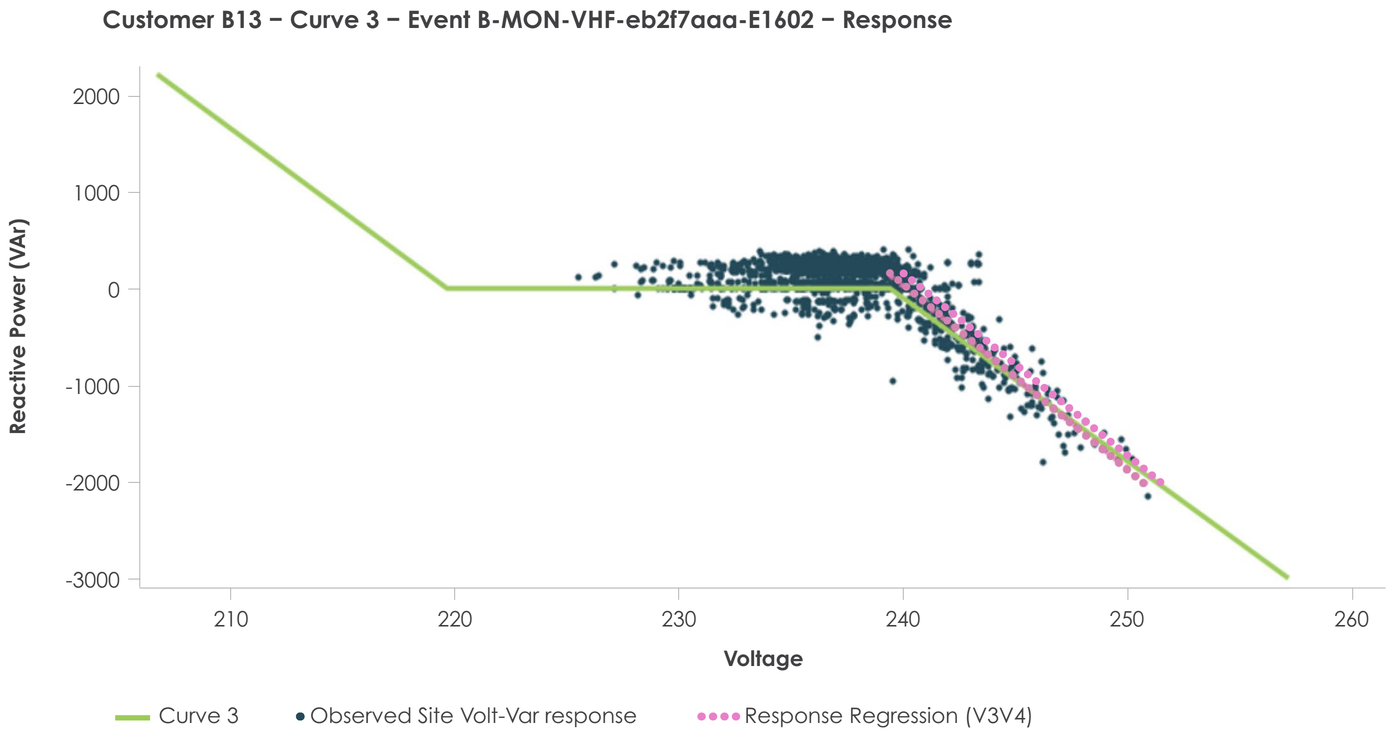
Table 21 outlines the Volt-VAr curve definitions.

Table 21: Volt-VAr curve definitions

Curve ID	Curve Type	Description	V1 / Q1	V2 / Q2	V3 / Q3	V4 / Q4
1	Generic/Default	Aligns with AS4777.2:2015	208 / 30%	220 / 0%	241 / 0%	253 / -30%
2	Generic/Default	Victorian DNSP standard	208 / 44%	220 / 0%	241 / 0%	253 / -44%
3	Generic/Default	Aligns with AS4777.2:2020	207 / 44%	220 / 0%	240 / 0%	258 / -60%
4	Custom	Custom curve (Early Q)	207 / 60%	220 / 0%	235 / 0%	245 / -60%

Figure 116 provides an example of a voltage management event.

Figure 116: Voltage management service event (29thth March 2023) verification conducted by the DNSP

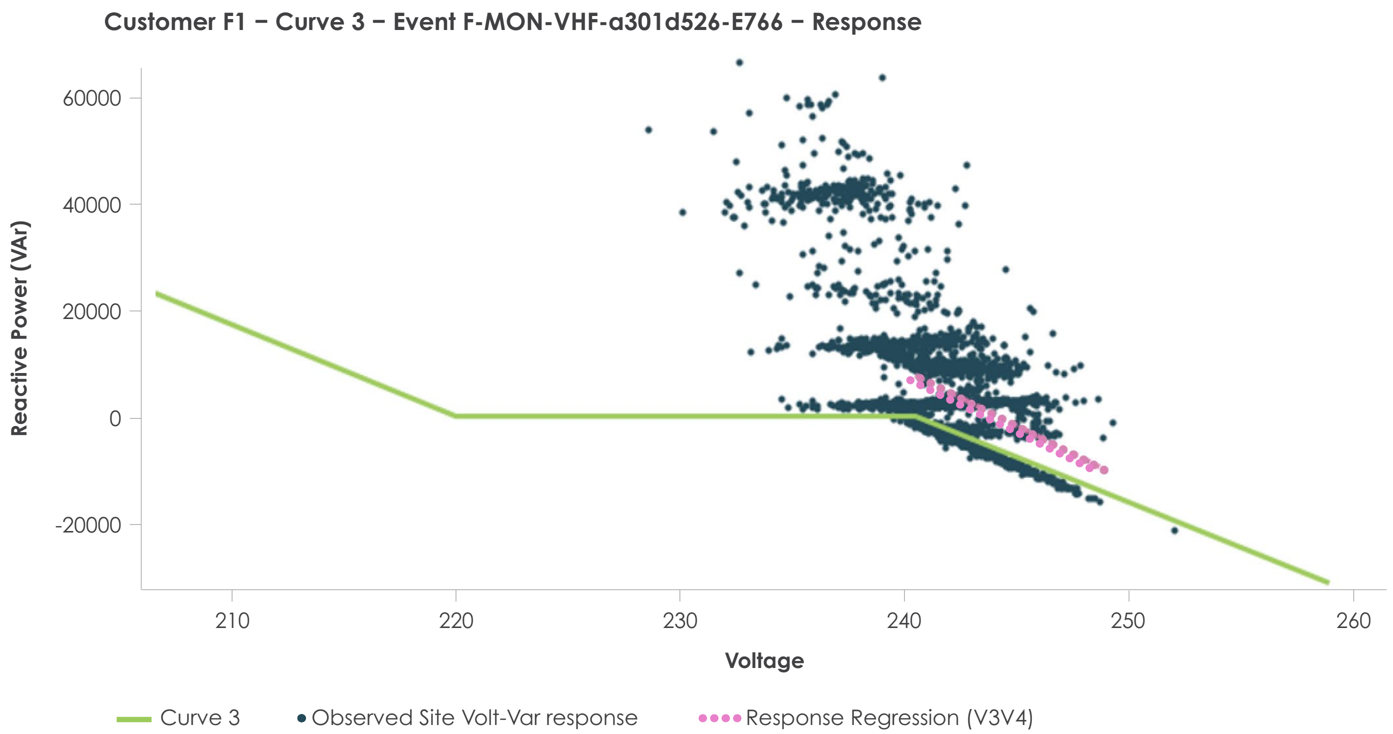


This provides an example of the aggregator's devices responding to and following the prescribed Volt-VAr curve successfully. This is reflected by the curve (the green line) and Volt-VAr points (the blue dot points) aligning.

To achieve this, the aggregator schedules the Volt-VAr curve on the inverter for the event duration specified in the arming signal. During the project, the DNSP provide the arming signal with 1 day notice. The aggregator could schedule this remotely, and ensure it takes effect at the required time, but there is nothing else the aggregator could do to prepare for it.

Figure 117 provides an example where the aggregator's devices did respond to, and follow, the prescribed Volt-VAr curve correctly; however, the measurement of verification occurred at the site and not the inverter. Therefore, a consideration for DNSPs will be whether there is value in procuring inverter level services, noting this only influences the site voltage, rather than prescribing a site level outcome.

Figure 117: Voltage management service event (7th November 2022) verification conducted by the DNSP



As shown in Figure 117, the Volt-VAr points do not align with the curve (the green line). As noted in the previous example, there is nothing the aggregator can do to prepare for the event other than schedule the Volt-VAr curve in the inverter to activate during the event. In this example, the customer's uncontrolled load was significantly impacting the observed delivery of reactive power at the smart meter. The appliances within the NMIs in the LSE portfolio providing the services produced significant amount of reactive power for which there was insufficient compensation.

This particular site was a C&I customer. When a motor consuming energy at the customer site stopped, it caused large fluctuations of reactive power. What this example identified was that some C&I sites with unpredictable consumption patterns may not be suitable at certain times (though there may be certain times when they could be; for example, during weekends if the motor is not running or is likely to stop during the day). As such, a customer site where the load can vary significantly may not be suitable to provide voltage management services because the aggregator does not have sufficient levers to control the impact on the delivery of the service.

As discussed, while an LSE portfolio comprising multiple NMIs could deliver voltage management services, each NMI providing the service is assessed for delivery. This is because voltage management services are even more localised than demand services. The service is required to alleviate constraints around a localised set of NMIs, whereas demand services are required to alleviate constraints for a transformer that is further upstream in the network.

The voltage management field tests highlight further work is required to confirm that the aggregator has successfully delivered the service, as the data at the inverter terminals are generally not available to the DNSP for compliance verification.

The key consideration is not whether the DNSP can get access to that data; rather, it is the independence of the assessment. DNSPs may prefer to rely on their own data rather than relying on the aggregator to provide information to verify delivery. In terms of access, if there were no other independent data available for verification, one option could be for the DNSP to include data provision into the contract.

This highlights another potential use case where a DER data hub and register may support efficient outcomes. If Volt-VAr curve settings are included as a data field, the aggregators could notify the DNSPs when these settings are updated to deliver a service, and DNSPs could see the settings change in the register. Inverter level performance data could also be efficiently sent to DNSPs to verify performance, which may be more cost-effective than procuring smart meter data (e.g. outside of Victoria).

7.3.3 DNSPs should consult with industry to develop an agreed approach on how delivery of NSS is assessed and validated

In Project EDGE, a 90% compliance metric was set for LSE tests. This meant a single instantaneous measure outside the 90% target would result in a service failure. The key learning during field trials was that if a strict compliance metric is applied, aggregators will need to include a 'buffer' of over-delivery to ensure compliant delivery, which is similar to how VPPs deliver FCAS.[323]

In real-world operating conditions, no delivery of service will be perfect. Conformance measurement generally identified minor performance data spikes deviating from target capacity and at least a small number of immaterial spikes. For example, if a delivery target for a high firmness event was 15kW export for a 3-hour duration, an aggregator would not deliver precisely 15kW for the entire duration. Delivery may deviate a few watts or kW at times during that period.

DNSPs need to define verification processes, cognisant of the constraints they are trying to manage while not inhibiting LSE uptake by aggregators by applying harsh penalties. Accordingly, DNSPs should consult with aggregators to identify approaches that strike the appropriate balance.

INSIGHTS

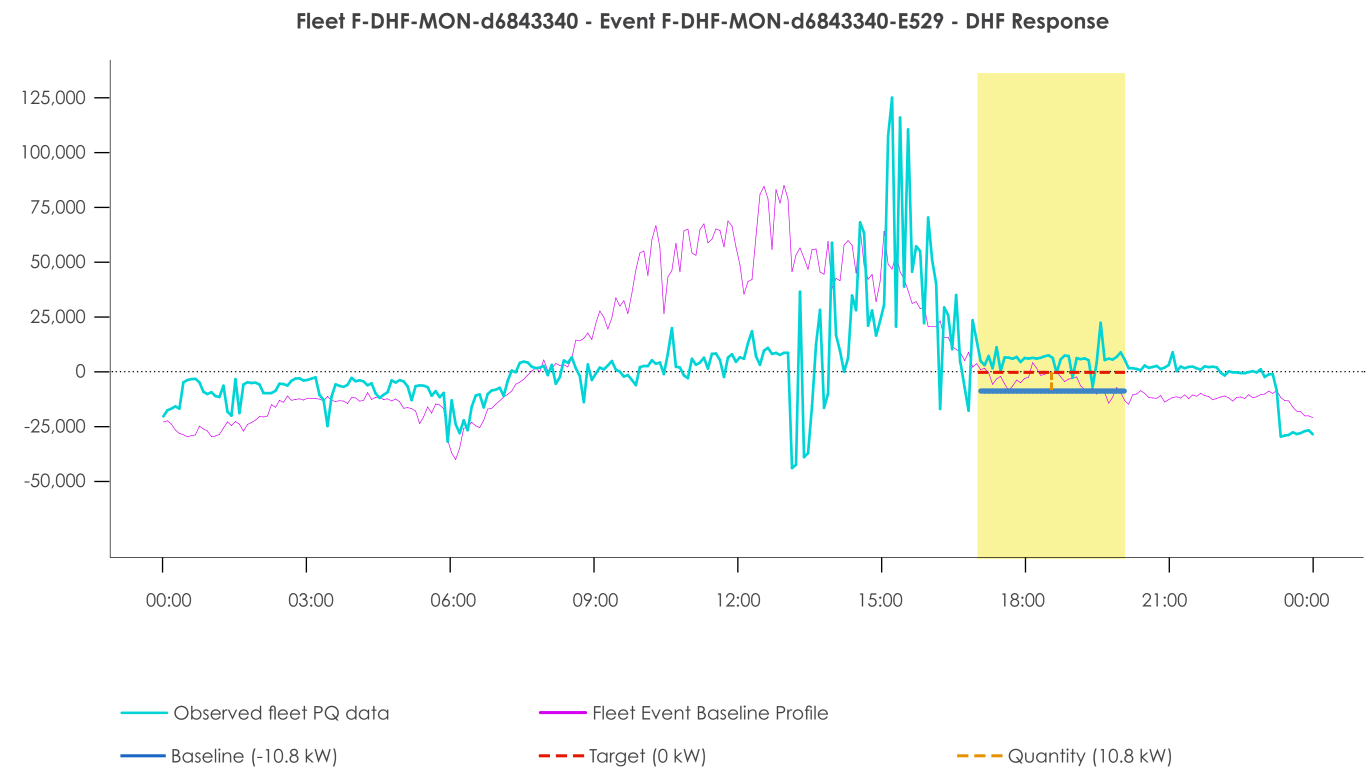
Exploring the feasibility of a nationally consistent approach to delivery of NSS

It would be ideal for industry to develop a nationally consistent approach to delivery of NSS, as this would make it easier for aggregators to scale across networks. The feasibility of a national approach should be explored in the recommended industry guideline for consistent service definition among DNSPs.

Figure 118 illustrates the impact of a compliance metric. It provides an example of a demand decrease, high firmness event that occurred on a weekday in spring, and for which the aggregator was evaluated as having delivered the service successfully. The event occurred from 11:00 and 14:00 (EST). The demand decrease target was 0kW for a duration of 3 hours from 11:00 to 14:00 (EST).

323 AEMO. 2021. AEMO NEM Virtual Power Plant Demonstrations: September 2021 Knowledge Sharing Report #4, p 7. https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-4.pdf?la=en

Figure 118: Demand decrease, high firmness event (11th November 2022) verification conducted by the DNSP



PERFORMANCE METRICS		
Metric	Result (Interval Energy Data)	Result (Power Quality Data)
Event Compliance (%)	100%	4.62%
Event Performance (%)	100%	96.91%

The cream shaded area represents the LSE event period. The purple line reflects the LSE portfolio's baseline profile. The black line reflects the observed LSE portfolio power quality (PQ) data. The demand decrease target for this event was 0kW (the solid black line).

The DNSP verified that the aggregator passed both in performance and compliance (see section 7.3.2.3 for details on the approach). The figure shows the observed PQ data was not a solid flat line consistently exporting 0kW. Rather, it spikes for the duration of the event. Accordingly, had a 100% compliance metric been set, the verification assessment would have led to different results.

The discrepancy in the event compliance score between energy and power quality data is a result of several five-minute instantaneous samples well under the target, significantly impacting the score, whereas it had a lesser impact on the energy data calculation, as it is an accumulation over the 30-minute interval. This highlights that the measurement mechanism (interval energy data or PQ data) will also lead to different results.

Industry will need to decide on a trade-off: higher compliance thresholds will be more expensive for aggregators to deliver and could lead to lower quantities being offered. AusNet's preliminary view was the duration and consistency of delivery was more important so long as it was within target thresholds.

In terms of enforcement, there would need to be contractual limits on the number of arming signals an aggregator can reject. Contractual penalties would need to be material enough to disincentivise an aggregator rejecting beyond contractual limits, but not more than the value provided by delivery.

7.3.4 Several factors could impact aggregators' ability to deliver local NSS

Aggregators will need to consider key factors that could impact the successful delivery of local network support services

Insights from LSE field trials identified the following key factors that aggregators may need to manage to mitigate impacts to the successful delivery of local NSS.

7.3.4.1 Capacity forecasting capabilities

Aggregators participating in LSE would need to regularly model changes, such as seasonal demand, that affect delivery, including regularly updating historical data. Initial development of capabilities will require a lot of testing to correct modelling challenges.

Costs to improve modelling can be a significant hurdle. Participating in multiple services could provide aggregators with an opportunity to spread the investment in modelling capabilities. For example, aggregators participating in local NSS need to develop forecasting capabilities and would have the modelling building blocks in place as they reach a scale where participation in wholesale services is needed. Enhancing models for wholesale (or vice versa) could therefore present an incremental cost that could be offset by the additional revenue that could be obtained.

7.3.4.2 Considerations of customer type, load profile accuracy and location of customer sites within the LSE portfolio

LSE field tests showed the demand profile of some C&I NMIs in the LSE portfolio may be less predictable. As such, aggregators' forecasting and coordination logic needs to take this into account. Tests showed C&I NMIs in the LSE portfolio with atypical demand patterns may have challenges delivering high firmness services. LSE portfolios with customer sites with unpredictable demand may be more suitable for low firmness services, where aggregators are only required to provide as much energy as the portfolio is capable of providing.

Aggregators will need to carefully consider customer acquisition strategies so that their VPP portfolios have the required capabilities and can mitigate factors impacting delivery. Aggregators may need to qualify sites to participate, taking into consideration issues such as whether there are reliable and predictable demand patterns and if meters are appropriately configured to record export. It is important to note that not every customer site may be suitable to utilise for local NSS.

The location of customers will also be an important consideration when acquiring customers, given the localised nature of NSS requirements.

The use of hybrid inverters is a configuration that requires further exploration. Hybrid quantities are net of solar and battery, and the field trial aggregators noted it was hard to model each independently. Additionally, each (solar and battery combination) cannot be controlled independently – the aggregator could coordinate the inverter to do X, but could not coordinate the battery to do Y or the solar to do Z.

Due to these challenges, throughout the Project EDGE field trials, sites with hybrid inverters did not meet the expected dispatch set point by about 100-300W compared with non-hybrid inverters.[324] While this is immaterial for a single inverter, at scale it could impact reliable service delivery unless the aggregator factors in the issue it experiences with hybrid inverters and always aims higher to compensate for it.

7.3.4.3 Service resilience considerations

The number of sites that can be acquired within the local network service area under constraints will be another significant factor for aggregators to consider when building their LSE portfolios. More acquired sites within the same constrained network area will provide more resilience and firmness to an aggregator's portfolio and its local service provision.

To provide local NSS, aggregators have a smaller pool of resources available to fulfill a service need because they are bound locally within the network, compared with wholesale services that can be delivered by DER portfolios spread over a wide geographic area.

Another potential factor relating to service resilience is that an LSE portfolio with only a single site could carry more delivery risk. Specifically, a site with less predictable load and small DER capacity could result in failed delivery because there are no other sites to compensate if demand varies or the forecast is inaccurate.

324 For example, when planning to meet a target for an event, an aggregator would set instructions in individual inverters in its LSE portfolio to cumulatively meet the target. In the case of hybrid-inverters, they were falling short. In other words, non-hybrid inverters were able to meet the instructions whereas the hybrid inverters were less reliable in hitting the target.

However, a single site with predictable load, or with over-sized solar and battery, could be very predictable for local NSS.

High firmness services LSE portfolios therefore require multiple sites to provide greater confidence of delivery or a single site with predictable load and appropriately sized solar and battery capacity. As such, aggregators may need to consider oversizing their portfolios to deliver reliable services.

7.3.4.4 Customer site and DER device communication outages

The design of the local NSS tested in the Project EDGE field trials accommodated aggregators losing communications with devices and sites because the aggregator could reject the arming signal and opt out of providing a local NSS. However, for a high firmness service, this would trigger a contract penalty. Additionally, aggregators would also need to develop coordination logic to compensate if devices go offline during an activated service. This capability is also relevant for wholesale services and is discussed further in terms of communications and compensatory controls section 5.3.2.7.

A communications outage could occur during an activated service, but coordination logic would mitigate the risk of failing to deliver services. To further mitigate the risk, consideration of outages needs to feed into the calculation of quantity that can be delivered. For example, in Project EDGE, the DNSP specified the target quantity for a high firmness service. If an aggregator's portfolio is not over-sized (or its bid for the service did not allow a headroom to account for operational error) and the target quantity is close to the highest quantity the aggregator portfolio could technically deliver under that constraint, the aggregator may be unable to achieve the target.

Unless there is compensatory headroom, a communications outage may cause under-delivery of a service. Committing to deliver services that are close to the limits of portfolio capacity increases the dispatch non-conformance risk. As such, a portfolio needs to have sufficient headroom capacity to pick up any unforeseen deficits.

While an aggregator would be unlikely to offer the full portfolio at any given time, this is a consideration that aggregators will need to take when developing their portfolios and capabilities for delivering local NSS. These considerations also apply to delivering other types of services and are discussed further in section 5.3.2.7.

Communications reliability is also lower in regional areas. Depending on the data communications standards that are applied to certain DER services, aggregators may qualify their customers based on the strength and reliability of their communications to ensure compliance with requirements. The same principle could apply when aggregators are considering acquiring regional customers for an LSE portfolio.

Alternatively, if an aggregator does acquire a significant regional LSE portfolio, it will need to develop mitigating strategies to manage communication outage impacts to its portfolio's resilience, firmness and service provision. Mitigating strategies may include having communications redundancy or increasing the amount of headroom in a portfolio.

7.3.4.5 Device testing

A key lesson from the field trials was the need for thorough testing of device capabilities, which are dynamic over time. There were many instances where the nameplate of the device was not the actual capacity.

Device output can vary based on multiple factors, including ambient temperature, state of charge, rated capacity issues, device firmware issues and asset degradation. Additionally, the nameplate capacity deteriorates over the life of a battery. This does not preclude devices from being acquired for an LSE portfolio; however, it would be the role of an aggregator to model these factors when developing its capabilities to provide all services (local and wholesale).

7.3.4.6 Other factors aggregators and DNSPs should consider in the design of local network support service exchanges

Experience from the LSE field trials and discussion with the aggregators and the DNSP on the performance and results, literature review and the project's detailed design process has uncovered other factors to consider in the design and evolution of LSE mechanisms over time.

Process to amend contracts and to remove and enlist new devices

It was observed during LSE field trials that there will be occasions when a device at a site goes permanently offline or is removed from the aggregator's portfolio if the customer churns. This is also a consideration for wholesale market participation; however, due to the lower volumes of DER capacity relied upon to deliver any given local service, it is a more pertinent to LSE participation.

Service type is also a factor. Low firmness services may not be impacted (unless a single site providing the service churns) as the service requires maximum available import or export without a specific target. On the other hand, high firmness services like those considered in Project EDGE would include contracted volumes (e.g. kW). There would likely need to be a streamlined process to amend the contract to adjust the volume commitment if the aggregator deemed its ability to provide the service as unreliable following the exit of these devices/sites from its portfolio.

This process could also be used when new sites are added to the aggregator's portfolio for a particular network location or if there is a material change to its capabilities. The DNSP and aggregator would need to agree amended contracted values in terms of baseline (if used) and quantities for services (and any associated changes to the payment agreements). As this process would be ongoing, it should be as streamlined as possible to avoid a layer of bureaucracy that serves as a barrier to LSE participation for aggregators.

Transparency mechanisms

Aggregators noted that having information about the types of network issues in specific network locations would help them target their customer acquisition activities.

Longer notice about network areas where the DNSP has assessed potential issues in the future (e.g. providing the information about stressed network areas with a 12-18 month horizon) would also assist aggregators to develop targeted acquisition programs in those areas. The Distribution Annual Planning Report (DAPR) process could be leveraged for this purpose. DAPRs identify existing and emerging network limitations, and identify and propose credible options to alleviate or manage these limitations.[325]

Aggregators would need to consider sufficient timeframes to acquire a level of customers with DER devices that would be material enough to help with the potential network issue.

Overall, aggregators noted that transparency of information about the affected network areas, and clear indications of timeframes regarding when the network issues are likely to need support, would assist them recruit customers for LSE portfolios.

How an affected area is communicated will need careful consideration. Defining a geographic area could be helpful but also misleading for aggregators as the electrical location of customer sites that could assist with a given constraint, as defined by the network topology, can differ to arbitrary geographical boundaries such as post codes or streets.

Another consideration is customer protections. If DNSPs provide specific NMI-level information, this could create unintended impacts on customers; for example, an overload of targeted marketing approaches in identified areas.

7.3.4.7 Dispatch performance during LSE events

Field trial performances demonstrated that aggregators can reliably deliver NSS while also managing wholesale market participation by adjusting wholesale bids to incorporate resources that must be dispatched to deliver a local NSS, and following wholesale dispatch instructions accurately. This demonstrated the ability to optimise VPP performance to deliver, and 'value stack', multiple electricity services simultaneously. See section 5.3.2.9 for a discussion of 'value stacking' field test results.

The performance observed in Project EDGE provides encouragement for DNSPs to rely on DER to deliver firm services to manage network constraints. Confidence in managing constraints in this way can be built up over time through a track record of DER delivering NSS. This builds on the learning from other trials, such as Networks Renewed, that also proved this at small scale.[326]

Project EDGE did not field test how aggregators responded to conflicting wholesale market and local NSS arming signals. However, AusNet analysis suggests that for the vast majority of the time, local and wholesale prices would be complementary and any conflict – such as a high wholesale price (e.g. triggered by a large generator outage) during a demand management service window attempting to lower voltage by reducing export (achieved by reduced generation or increased controllable load) – would occur in localised geographies and not across the entire distribution network.

Meanwhile, aggregators noted they would generally prioritise materially higher wholesale prices over local services with the exception of firm services, recognising:

- Value in service revenue certainty
- DNSP trust
- Avoiding potential contract penalties
- The infrequent and unpredictable nature of high wholesale prices.

Nonetheless, the potential contract value from firm LSE service provision compared with the opportunity cost of committing that DER capacity instead of other potential price signals (wholesale market, LSE low firmness, retailer hedge services) is a factor that aggregators would need to consider when deciding to participate in providing multiple services.

Aggregators may need to consider several potential opportunity costs that would factor into their willingness to deliver local NSS. These opportunity costs include:

- **Higher energy costs:** To deliver a firm local NSS, there may be times where an aggregator could be called to import energy during periods of high electricity wholesale market prices and export at negative prices. For an aggregator exposed to the wholesale price, that would result in higher energy costs for the aggregator. It could also lead to energy waste and higher costs overall.
  - Such scenarios are unlikely because the nature of NSS is that they are used to alleviate constraints in a local network area. This means that it would not require an aggregator to use all the devices in its portfolio – only those within the constrained network area requiring the service. Accordingly, the aggregator may be able to offset the misalignment of the type of NSS required and wholesale price, by providing wholesale services to maximise the prices using other devices in its portfolio.
  - This would not be a concern for an aggregator providing a combination of self-consumption and LSE services only. For all aggregators, there are operational costs to deliver any service (resourcing, system, etc).
- **Missed revenue opportunities:** Energy co-optimisation can create opportunities to generate revenue by participating in other market services. However, if these opportunities are not pursued because a contracted local NSS must be delivered, it could result in missed revenue potential.

  For example, if the aggregator was called upon for a demand decrease service at a time the wholesale electricity market price was high, the aggregator could benefit from both. However, depending on the contract for the NSS, the revenue the aggregator could receive from only providing wholesale services could be higher. As such, this may represent a missed larger revenue opportunity.

  Similarly, and related to higher energy costs above, if the wholesale price was low and at the same time an aggregator was required to export to deliver an NSS, it would be a missed opportunity for the aggregator to import to make the most of the low wholesale prices.
- **Battery degradation cost:** Batteries are subject to degradation over time, as they are cycled through periods of charging and discharging. Repeated cycling can cause the battery's capacity to gradually decline, reducing its ability to hold a charge and provide consistent power output. The rate of battery degradation can be influenced by the control cycle for delivering local network services. This would have customer impacts as the customer's asset lifetime is reduced.

Ultimately, the specific considerations for an aggregator's local NSS contract will depend on the specific requirements of the service, as well as the regulatory environment and the other external factors discussed in section 7.3.2.

325 Clause 5.13 of the NER prescribes the distribution annual planning process, including the scope and need for DNSPs to identify limitation on its network and whether corrective actions are required to address these. DNSPs are also required to engage with non-network providers and consider non-network options for addressing limitation in accordance with the DNSP's demand side management strategy.

326 ARENA. 2021. Networks Renewed. https://arena.gov.au/projects/networks-renewed/; Ausgrid. N.d., Battery Virtual Power Plant Trial. https://www.ausgrid.com.au/Industry/Demand-Management/Power2U-Progam/Battery-VPP-Trial

INSIGHTS

Field trial findings on the technical capability of DER to provide network support services

Overall, performance data from the field trials in Project EDGE have shown technical capability (at small-scale) for DER to provide network support services.

However, no NMIs participating in the field trial were located in network areas with actual constraints. This project limitation meant field tests were not able to show whether the services would alleviate network constraints.

However, the technical capability results indicate that with sufficiently large LSE portfolios in network constrained areas, coordinated DER could provide services that a DNSP could utilise to manage network constraints.

7.3.5 Standardising network support services trade

A Local Services Exchange could help standardise network support services trade

Project EDGE demonstrated, at small-scale, how an LSE could support two of the five standardisation factors for network support services outlined in section 7.1 above.

- Service definitions – the demand increase and decrease services tested in Project EDGE (discussed in section 7.3.2) are services that other DNSPs in the NEM have attempted to procure.[327] The peak demand and minimum load network constraints such services are attempting to alleviate are common for many networks in the NEM. While the specific characteristics defined for Project EDGE may not be those ultimately adopted by industry, the project showed that the concept of defining and standardising the characteristics of common NSS is feasible.
- Data exchange – data for demand-related[328] NSS tested in Project EDGE were exchanged successfully between AusNet and two aggregators by establishing new channels on the DER data hub.[329]

7.3.5.1 How service definitions could be standardised

Network support service types for coordinated DER are not widely adopted in Australia. Where they are procured, they are point-to-point and not standardised. Project EDGE has shown the standardisation of characteristics that define NSS could be possible across some dimensions and that the services may be helpful to DNSPs.

To achieve standardisation of service definition, industry could consider and expand the service characteristics defined by AusNet in an industry guideline to standardise the characteristics that make up an NSS.

An industry guideline could also aim to standardise contractual terms and the way that services are transacted. Standardising both these factors across LSEs could simplify the experience for aggregators and also reduce aggregators' operational costs to deliver NSS, resulting in additional value that could be shared with customers.

While efforts to standardise disproportionately benefit aggregators, it is also beneficial to DNSPs because it is essential to seeding a liquid market of service providers for DNSPs. In turn, this leads to price competition (from bidding) and resilience of service (if one aggregator pulls out, it is more likely there will be other aggregators there to take its place).

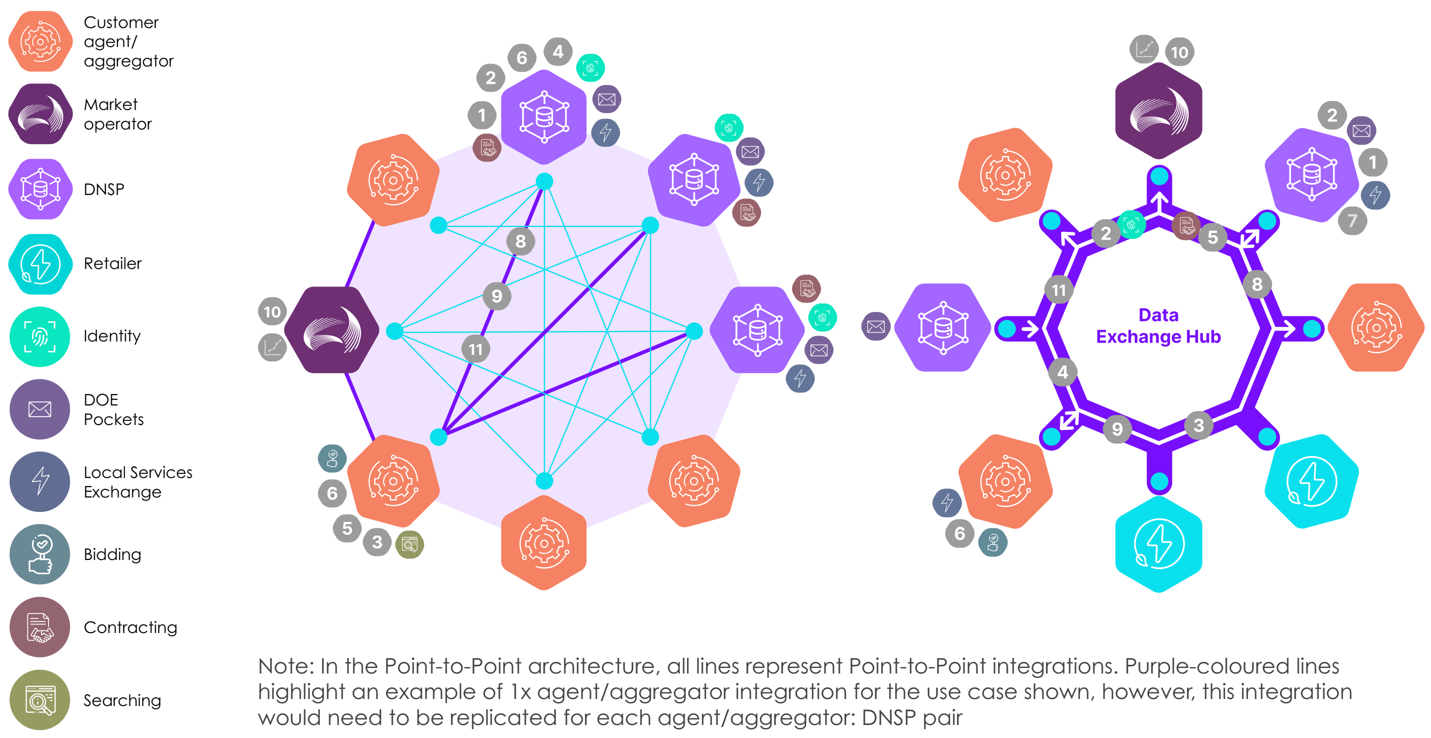
It is important to note that there should be a direct correlation between the level of standardisation across regions and scalability on NSS. As a result, broad stakeholder engagement for the development of the guideline, and commitment to its implementation, should deliver better outcomes for the industry and consumers.

Findings from the CBA supported standardisation. The CBA found standardising NSS could lower barriers to its adoption.[330]

7.3.5.2 How connecting an LSE to a DER data hub supports standardisation

A step-by-step comparison of a point-to-point LSE architecture and the Project EDGE design for how local services could be procured through an LSE connected to a DER data hub is shown below.

Figure 119: LSE operations with point-to-point architecture (left) and data hub approach (right)



Note: In the Point-to-Point architecture, all lines represent Point-to-Point integrations. Purple-coloured lines highlight an example of 1x agent/aggregator integration for the use case shown, however, this integration would need to be replicated for each agent/aggregator: DNSP pair

Table 22: LSE operations with point-to-point architecture (left) and data hub approach (right)

Step	Point-to-point	DER Data Hub
1	Each DNSP establishes an LSE interface	Each DNSP establishes an LSE interface
2	DNSPs post service needs *Note:* Service definitions may not be standardised across the DNSPs for aggregators	Using existing data hub integration, DNSP establishes LSE channel(s) to signal service needs *Note:* Any existing hub integration can be leveraged in this use case including existing identities managed by AEMO. This example assumes DNSPs and aggregators are already integrated to the hub for the DOE use case

327 See for example, Request for information: Non-network solution offering available at Citipower, Powercor and United Energy. Citipower, Powercor and United Energy. N.d. https://media.unitedenergy.com.au/forms/Request-for-Information-Non-Network-Solution-Final.pdf

328 This was not used for the voltage management services due to time limitations.

329 Project EDGE. 2023. DER Data Hub Lessons Learnt Report June 2023, p 71, Appendix 1. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

330 Deloitte Access Economics. 2023. Project EDGE CBA Final Report, p.88. Deloitte Access Economics. 2023. Project EDGE CBA Executive Summary, p.24. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

Step	Point-to-point	DER Data Hub
3	Aggregators search each DNSP website or exchange to discover local NSS opportunities Note: Service discovery is aggregator driven	DNSP uses broadcast messenger function to notify registered aggregators/agents on the hub of the channel, service opportunities, contract terms and how to connect Note: Service discovery can be promoted by the DNSP.
4	Aggregator negotiates and contracts with each DNSP they want to service Note: For aggregators, the contracts across each DNSPs may not be standardised	Aggregator existing integration to the hub used to apply to subscribe to DNSP LSE channel(s)
5	Integration established between aggregator and DNSP. The aggregator undertakes an organisation identity and portfolio registration process with each DNSP Note: The Identity verification process may not be standardised across actors. If several identities exist for one aggregator, it can be managed by different parties	DNSP approves access to their LSE channel based on aggregator credentials. Aggregators bid on services they are qualified for
6	Aggregators bid on services for which they are qualified	DNSP awards contract
7	DNSP awards contract (not shown)	DNSP issues service activation notice
8	DNSP issues service activation notice	Aggregator receives activation notice and prepares portfolio
9	Aggregator receives activation notice and prepares portfolio	Aggregator updates market offer to AEMO that includes capacity committed to all DNSPs through existing hub integration
10	Aggregator updates market offer to AEMO that includes capacity committed to all DNSPs through separate integration Note: Provision to AEMO through existing systems for market services, assuming material portfolio size to become a wholesale market participant	Service verification obtained through smart meter data or through telemetry exchanged through the DER data hub
11	Service verification obtained through smart meter data or other method if required Note: Service verification data requirements may not be standardised for similar services across the DNSPs	This process repeats with any updates to the aggregator's portfolio Note: The hub maintains participants and portfolio mapping to facilitate B2B interactions
12	This process repeats with any updates to the aggregator's portfolio Note: Aggregator makes DER portfolio updates with each counterparty; this process may not be standardised	

Source: Project EDGE, DER Data Hub Lessons Learnt Report.[331]

If an LSE connected to a DER data hub model for procuring local NSS at scale is explored further outside of Project EDGE, the table below outlines some potential linkages between the DER data hub and LSEs that could be considered in designing both systems, using the stages of service lifecycle outlined in Figure 102 in section 7.1.

331 Project EDGE. 2023, DER Data Hub Lessons Learnt Report June 2023. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-der-data-hub-lessons-learnt-final-june-2023.pdf?la=en

Table 23: Potential linkages between DER data hub and LSE

Stage of service lifecycle	Description of potential linkage to the DER data hub and register

Identify
Show location and capacity of DER available for network support service
	• A geospatial mapping capability, either on the DER data hub or in separate LSEs linked to the DER register, could be used to show:
	  • DNSP information on current and forecast constraints
	  • Quantity of DER capable of being coordinated by postcode or by distribution substation (linking to the DER register)
	  • Quantity of coordinated DER registered in an aggregator portfolio (by linking DER Register and portfolio management information if captured in a future iteration of the DER Register). This would enable DNSPs to see available DER capacity registered in VPPs by location; for example, to view their proximity to a network constraint
	  • Location of public EV chargers (linking to the DER register if these are captured in future)
	  • A challenge that will need to be addressed is ensuring the DER register is maintained up to date and making updates more dynamic (e.g. closer to real-time).

Define Show the network support service characteristics and terms required by the DNSPs	• DNSPs could define the services they want to procure in regional LSEs. These could align to industry agreed guidelines. • The defined services that DNSPs want to procure could be shown on the geospatial mapping capability outlined above. If coordinated DER is shown on the same map, DNSPs could view the total capacity of DER near a relevant constraint.
Enrol VPPs enrol for pre-approval, including capability verification	• The use of consistent Identity and Access Management on the DER data hub and register means that aggregators could enrol/update their portfolio across the NEM in one system, and allocate DER to different sub-portfolios for different wholesale or local services.[332] • Each DNSP could view aggregator portfolio data and sub-portfolios created for NSS delivery in specific parts of the network. • An updated DER register could incorporate portfolio management data so that the integrated data is a consistent source of truth that AEMO, DNSPs and aggregators can use to enrol/update/view DER and aggregator portfolio data (whilst adhering to regulations on private and protected data). • An updated register could also be used to record inverter setting and compliance tracking. • Pre-qualification testing data could be exchanged through the DER data hub, leveraging such testing done for other services such as with other DNSPs, market services or others such as RERT.
Engage Specific services are posted, offers received and standardised contracts exchanged	• DNSPs could define contractual terms for the services they have designed in regional LSEs that align to industry agreed guidelines. • DNSPs could view aggregator bids/offers for a specific network support service and select service providers in their LSEs. • If the contracts are digital, the messaging to agree pre-defined contractual terms and engage on a service could be exchanged through a DER data hub.

332 For clarity, the sub-portfolios would be within the aggregator's own system and not registered with the DER data hub or with the DNSP. The DNSPs would refer to the DER data hub as the master source of truth.

Stage of service lifecycle	Description of potential linkage to the DER data hub and register
Deliver and verify Service arming and dispatch signals, and performance verification data exchanged	• Operational signals to pre-arm or dispatch VPPs to deliver network support services could be sent from the DNSP via the DER data hub. • If required, VPP performance telemetry could also be sent from the aggregator to DNSP via the DER data hub. • Some services may be verified using smart meter data that DNSPs already have access to, in which case verification data can be sourced outside the hub.
Settle and report Standardised settlement mechanisms	• Settlement would likely occur through existing systems outside of the DER data hub. • Messaging to confirm telemetry validated successful delivery could be exchanged and recorded via a DER data hub, then settlement could occur through external systems. • Non-conformance could also be recorded, which may trigger a need for clawback through external systems. • The DER data hub could record the aggregated volume of services tendered for and delivered for aggregated reporting and visibility through AEMO and other permissioned stakeholders such as the AER.

7.3.5.3 TNSPs may also want to standardise network support services procurement in LSEs

The LSE aspect of Project EDGE has been focused on how DNSPs can efficiently procure NSS at scale. In future, however, TNSPs may be able to resolve constraints by engaging distribution connected resources to deliver NSS. The current process for TNSPs to procure NSS (such as Network Support and Control Ancillary Services) is through bespoke, bilateral contracts.

If such services are to be procured at greater scale, it could be more efficient to enable standardised procurement through an LSE, as a similar service lifecycle and similar categories of characteristics may apply.

In this case, the exchange may not be 'local', so more suitable terminology for the function could be a Regional Flexibility Exchange that both DNSPs and TNSPs could use to procure NSS / flexibility services from resources that are either distribution- or transmission-connected.

In developing such a process, potential conflicts between DNSP and TNSP requirements would need to be considered. The effect a TNSP network support service trigger may have on the DNSP's network performance and reliability would also need to be considered.

INSIGHTS

Considerations for standardising network support services

Development of an industry guideline to standardise or provide guidance on the characteristics and lifecycle of a local service, as well as transaction terms, would simplify the experience for aggregators and also reduce their operational costs in delivering NSS.

Ideally, the design of a DER data hub and register should coincide with the development of an industry guideline on NSS and consider potential integration points with LSEs in case a 'Connected' model for procuring local services is advanced in future – for instance, for standing data, telemetry and control signals.

The design of LSEs should also consider how TNSPs could use the LSE to efficiently procure network support services in future.

7.4 Key insights and implications for industry

As DNSPs procure NSS at higher volumes of capacity and transactions, digital solutions could improve the efficiency and scalability of these services. Project EDGE developed a design for a digital solution called a Local Services Exchange (LSE) and built and field trialled an LSE with two aggregators.

Project EDGE's research and field trial analysis provided the following key insights and implications for industry.

For policy makers

- Consider an industry-wide approach to standardisation of local network support services that covers common service definitions, contractual terms and the way services are transacted, while leaving flexibility for DNSPs to develop additional bespoke services to meet local network topographies and needs. Standardisation should also not hamper innovation by first movers.
- Consider developing standardised frameworks to enable the trade of local NSS to facilitate scale across DNSP service areas, noting that performance data from the Project EDGE field trials show technical capability (at small-scale) to manage network reliability through the provision of local NSS from DER and that lessons learnt in the UK indicate the development of scaled NSS trade needs to be facilitated through more standardisation, simplification and transparent decision-making.
- Recognise that broad engagement and commitment to implementation will be needed across industry – including policy makers, DNSPs and aggregators – to ensure a direct correlation between the level of standardisation across regions and scalability of local NSS.
- Further explore a Local Services Exchange framework connected to a DER data hub model to facilitate procurement of NSS and VPP participation to begin scaling. Consideration should be given to potential integration points such as standing data, telemetry and control signals. The framework should be linked to national mapping of EV charging infrastructure to identify opportunities for synergies.
- Consider developing a framework for local NSS now, so that efficient mechanisms are in place as DER scales – noting that in the short term, DER penetration may only be sufficient in localised areas to support participation in an LSE.
- In designing an LSE framework, confirm whether DNSPs are the appropriate industry participant to operate LSE platforms and consider how TNSPs could use the LSE to procure network support services in the future.
- Consider whether regulatory incentives are strong enough to encourage greater use of network support services.

For DNSPs

- Engage proactively with policy makers, aggregators and other DNSPs in developing consistent approaches to network support services.
- Consider development of an industry guideline to standardise (or provide guidance on standardising as much as possible) the characteristics and lifecycles of local network support services and transaction terms (e.g. common service definitions, contractual terms and the way that services are transacted).
- Engage pro-actively in developing consistent approaches to the provision of detailed information on forecast network constraints to enable aggregators to develop strategies to support the delivery of network support services.
- Recognise that broad engagement and commitment to implementation will be needed across industry – including DNSPs, aggregators and policy makers – to ensure a direct correlation between the level of standardisation across regions and scalability of local NSS.
- Consult with other industry participants on setting compliance thresholds in a way that balances network congestion management and the uptake of LSE services by aggregators.

For aggregators

- Consider participation in providing local NSS as a potential stepping-stone to access revenue to develop capabilities and systems to graduate to fully scheduled resources.
- When developing strategies for participation in the delivery of local NSS, carefully consider the key factors aggregators need to manage or mitigate impacts to successful delivery.
- Actively participate in consultation on setting compliance thresholds.

ROLES AND RESPONSIBILITIES

This chapter focuses on the research question:

How can integrating DER into the NEM facilitate efficient and scalable provision of local network support services (NSS) from DER so that network efficiency benefits are realised for all customers?

Overview

- Project EDGE tested the roles and responsibilities of AEMO, DNSPs and aggregators and retailers to consider whether their functions and capabilities needed to be expanded to perform DER integration responsibilities, rather than creating entirely new roles
- The independent CBA found that the aggregator role is a primary driver of the value identified in the CBA.
- Project EDGE identified three primary roles that would enable the integration of DER:
  - AEMO as the NEM Market and System Operator – responsible for security of the power system, and managing system security and the central dispatch process
  - DNSPs – responsible for managing their operating zone and enhanced with new capabilities to support DER integration, efficient wholesale market outcomes and efficient network development, and network capacity allocation
  - Aggregators and retailers – responsible for coordination of consumer-owned DER, for the delivery of services and/or to respond to market price signals, and complying with DOEs.
- The independent CBA conducted for the project found that this arrangement of roles and responsibilities facilitates a stepwise transition from existing hierarchical arrangements for managing the power system and would underpin the realisation of benefits from the integration of active DER into the NEM.
- If a decision is made to roll out DOEs (or at least initially, flexible export limits) to new PV installations as soon as practicable, a review of the NEM's legal and regulatory framework should be considered to provide clarity in the allocation of roles and risk.
- Project EDGE found that AEMO and DNSPs can build on their existing roles and responsibilities to efficiently and optimally coordinate DER operation within local and system limits as uptake scales.
- The Project EDGE field trial showed that while aggregators are able to conform to dispatch instructions, albeit inconsistently, there is a need to monitor conformance and develop enforcement mechanisms because breaches occurring at greater DER volumes could adversely impact local network and power system security. Project EDGE recommends developing and implementing a robust DOE conformance monitoring and compliance framework that separates duties in terms of DOE conformance monitoring, DOE conformance assessment and DOE compliance enforcement.
- Within this recommended framework, AEMO is responsible for wholesale dispatch conformance monitoring and the AER is responsible for DOE compliance enforcement.
- As dynamic connection agreements are rolled out for new DER connections, DNSPs, or if efficient, metering coordinators on behalf of DNSPs, should be responsible for DOE conformance monitoring. However, DNSPs should be responsible for DOE conformance assessment to ensure DER operation remains within network limits at all times. There may be a case for escalation to the AER in cases of repeated DOE conformance breaches not remedied by the aggregated to enforce compliance
- As VPPs scale, portfolio level conformance to DOEs may be necessary to mitigate local network and system security risk. A spectrum of approaches – from trusting aggregators to 'self-constrain' through to fully automated monitoring – is available to give AEMO, DNSPs and the overall market the confidence required. AEMO, TNSPs and DNSPs will need to collaborate on further analysis to identify the most appropriate mechanisms for VPP level DOE conformance at scale.

- Both AEMO and DNSPs will need to register VPPs and coordinate operationally to securely deliver and manage wholesale or local network support services. The use of common infrastructure to coordinate could avoid duplication and mitigate risk of errors. This could be via a DER data hub, as tested in Project EDGE (see Chapter 6).
- In a future system where DER are integrated into electricity markets, AEMO does not need to be responsible for co-optimising DER services. Project EDGE identified that aggregators are best placed to co-optimise DER for delivering multiple services. Performance in the field trial confirmed that aggregators were able to meet wholesale dispatch targets while simultaneously delivering local NSS.
- Project EDGE has produced a practical and economic evidence base that supports the case for a NEM DER data hub (see Chapter 6). Proceeding with a data hub will require consideration of design questions regarding who should own, govern, operate, develop/update and recover costs for a hub.
- Overall, industry and policy makers should collaborate to define roles and responsibilities based on these findings.

8.1 **Context**

One of Project EDGE's objectives was to develop a detailed understanding of roles and specific responsibilities that each industry actor should play in the integration of DER into the power system and electricity markets.[333]

There are three primary roles that will enable the integration of DER:

- AEMO as the Power System and Market Operator
- The Distribution Network Service Providers evolving to Distribution System Operators (DSOs)
- Aggregators and retailers as the DER customer representatives, coordinating devices for the provision of local network services and/or participating in the wholesale market.

AEMO and ENA collaborated on OpEN with stakeholders across the energy industry to identify the most appropriate frameworks for cost-effectively integrate DER into local distribution networks and the NEM. Supported by broad stakeholder engagement, OpEN identified a Hybrid model as the most appropriate framework. Accordingly, the OpEN Hybrid model represents a cross-industry collaboration on the most suitable framework for DER integration. However, recognising that there is no single definition of the Hybrid model, OpEN noted trials would be needed to understand the most effective approach to integrate DER and optimise efficiency and benefits for industry and consumers.

The OpEN Hybrid model provides a guide on the roles and responsibilities of these three actors.[334] This included the extent to which these roles and responsibilities deliver on the NEO and align with current roles under the existing regulatory frameworks.

OpEN also proposed that trials should be conducted to understand how a Hybrid model could best integrate DER.

333 UOM. 2022. Project Edge Research Plan p 20. https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35

334 AEMO and ENA. 2019, Open Energy Networks Interim Report: Required Capabilities and Recommended Actions. https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

INSIGHTS

Defining an Australian DSO

The NEM has included a definition of Distribution System Operator in the NER[335] since the first version became effective on 1 July 2005:

'A person who is responsible, under the Rules or otherwise, for controlling or operating any portion of a distribution system (including being responsible for directing its operations during power system emergencies) and who is registered by AEMO as a Distribution System Operator under Chapter 2.'

However, this definition is called upon only in the context of coordinating with AEMO (via TNSPs) on operational aspects relating to power system security. It does not include a role to enable system flexibility and support efficient wholesale market outcomes.

While there is no internationally recognised definition of DSO, the definition in the PJM power system in the US aligns with the general use of the term in the context of the energy transition:

'An entity that is responsible for the planning and operational functions associated with a distribution system that is modernised to accommodate and manage the operations of high levels of flexible assets while maintaining safe and reliable operation of the system.'[336]

Similarly, in Europe, the mission of DSOs in the energy transition is:

'… to operate and maintain the infrastructure that connects consumers and businesses with the local network and, through TSOs (Transmission System Operators), to the European transmission network. DSOs are the backbone that integrate up to 70% of renewable energy sources and enable consumers to participate in an increasingly decentralised energy world.'[337]

These definitions include reference to the traditional operational and planning functions of DNSPs in Australia, but also extend the role to specifically include the integration of DER.

The roles and responsibilities of a DSO in the context of the energy transition are yet to be defined in Australia.

336 PJM. N.d., Membership & Sector Selection. https://www.pjm.com/about-pjm/member-services/membership-and-sector-selection

337 DSO Entity, N.d., DSOs in the energy transition. https://eudsoentity.eu/dsos-in-the-energy-transition

8.2 **Approach**

Project EDGE tested the roles and responsibilities of these three actors aligned with the OpEN Hybrid model, with the objective of understanding whether DER integration responsibilities could be performed by expanding the functions and capabilities of existing actors in the NEM's current regulatory framework rather than creating entirely new roles.

At a high-level, the overarching responsibilities of the roles required to integrate DER under a Hybrid model approach are:

- **AEMO – in its capacity as the NEM Market and System Operator**
  - Under the NER, AEMO has overarching responsibility for security of the power system, including relying on the delegation of certain operational responsibilities to DNSPs (via the TNSPs) in relation to actions within their operating zone impacting system security.
  - AEMO is also responsible under the NER for establishing and managing the central dispatch process, including:
    - Quantifying and managing the secure technical envelope of the power system (operationalised through constraints), coordinating with TNSPs and DNSPs to ensure network limits are considered.[338]
    - Forecasting electricity demand and publishing spot price forecasts and pre-dispatch schedules.
    - Scheduling and dispatching resources participating in the wholesale markets (co-optimising energy and FCAS) within the secure technical envelope of the power system.
  - AEMO also manages wholesale market settlements
  - In Project EDGE, AEMO operated the data exchange infrastructure that facilitated the operational coordination between all trial participants. This extended on one of AEMO's current responsibilities, to operate the B2B e-Hub for the retail market (which is conceptually similar).
- **DNSPs – enhanced with new capabilities to support DER integration, efficient wholesale market outcomes and efficient network development**
  - Network optimisation: DNSPs are experts of their networks; as such, Project EDGE considered whether it would be appropriate that they were responsible for:
    - Optimising how they configure and operate the network
    - Calculating and communicating the limits of their distribution networks (referred to as DOEs, see Chapter 4 for more detail). This also gives AEMO confidence that power flows remain with network limits across the power system, supporting AEMO's overarching responsibility for power system security
    - Procuring / managing NSS to support efficient network operations and development
  - Network monitoring: to execute its role to optimise network operations, Project EDGE explored how DNSPs could require:
    - Visibility / monitoring of power flows and DER in the distribution network[339]
    - Monitoring of conformance to DOEs and DER technical standards associated with customer connection agreements
  - Support whole of system optimisation: Project EDGE also explored how DNSPs could utilise DOEs and/or flexible capacity in network infrastructure to support efficient whole of system outcomes to benefit all consumers. This is discussed further in Chapter 9.
- **Aggregators and retailers – responsible for coordination of consumer-owned DER, for the delivery of services and/or to respond to market price signals**
  - Currently, aggregators coordinate customer-owned DER devices to deliver electricity services. Retailers are also starting to coordinate customers' rooftop PV inverters to apply dynamic export limits in response to negative wholesale prices.
  - Project EDGE tested how DER aggregators can receive all external signals (prices and constraints) and optimise DER operations on behalf of DER consumers (including the co-optimisation of local NSS and wholesale services opportunities).

To understand whether the three primary roles were largely aligned to current roles, and to identify the expanded functions and capabilities required, Project EDGE completed the following research and analysis activities:

- Behaviour and performance of the capabilities developed for the field trial was analysed to inform whether the roles and responsibilities tested were appropriate. Project EDGE participants also gained insights from the detailed co-design and implementation of the capabilities tested.
- Engagement with project participants identified potential mechanisms for consideration related to VPP dispatch conformance monitoring, DOE conformance monitoring and compliance, and VPP level DOE conformance monitoring.
- Deloitte Access Economics was engaged to conduct a CBA on whether the concepts tested in Project EDGE deliver value to all consumers in line with the NEO. This included evaluating the ability of the roles and responsibilities arrangements to deliver economic value through techno-economic modelling and Multi Criteria Analysis of those tested in Project EDGE, as well as alternative arrangements within the Hybrid framework.

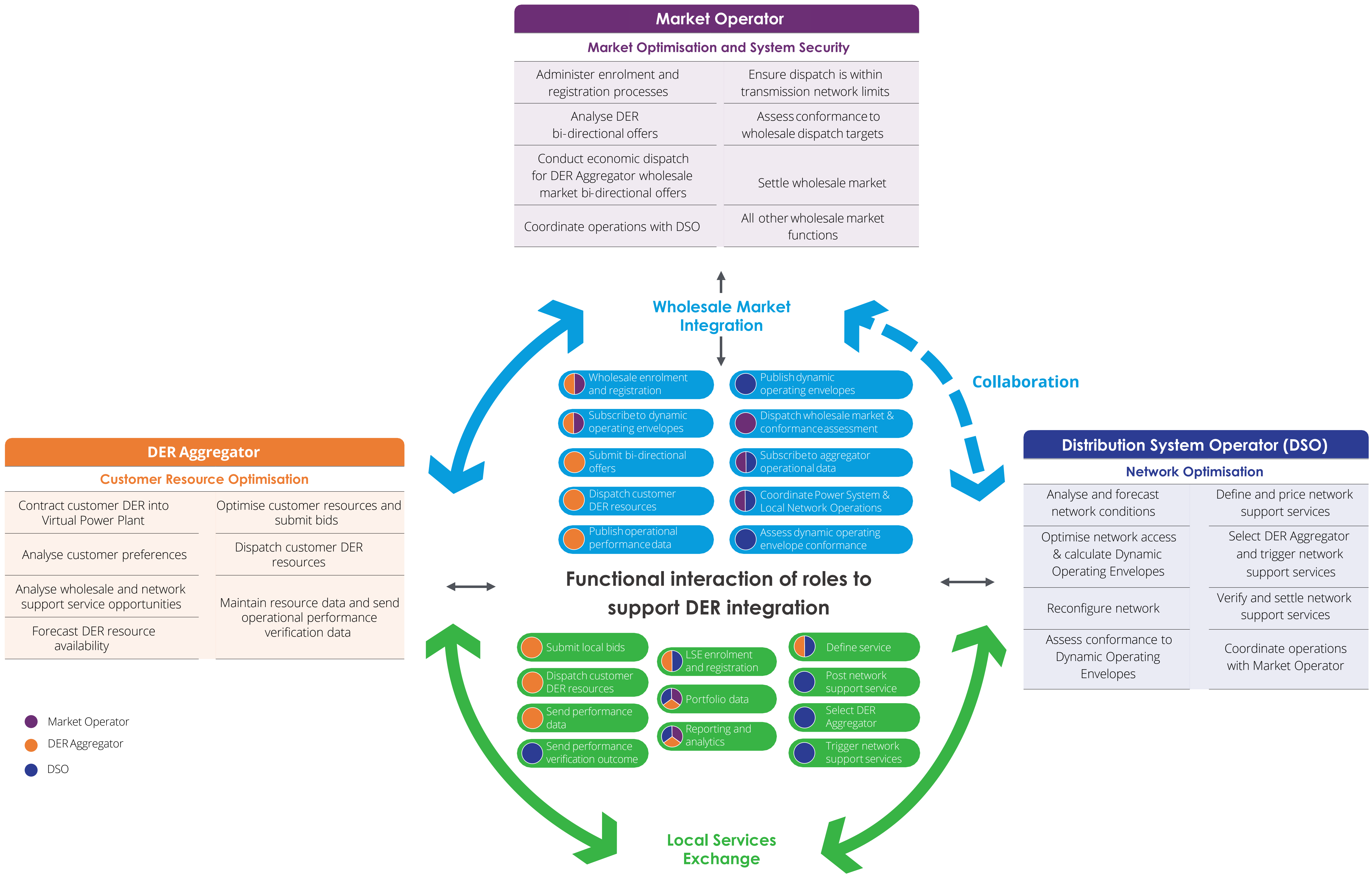
8.3 **Findings**

This section summarises the key findings on the roles and responsibilities recommended by Project EDGE to facilitate the coordination of DER at scale to provide wholesale market, NSS and other B2B services.

338 NER clause 3.8.1 provides that AEMO must operate a central dispatch process for certain units, loads and services to balance power system supply and demand and maintain power system security. Clause 3.8.10 provides that AEMO must determine any constraints on the dispatch of certain units, loads and services in accordance with its power system security responsibilities under NER Chapter 4. These responsibilities include ensuring interactions with DSOs (as defined in the NER) for both transmission and distribution networks so that power system security is not jeopardised by operations on the connected transmission and distribution networks (clause 4.3.1(w)).

339 Energy Networks Australia. 2020, Open Energy Networks Project: Energy Network Australia Position Paper, p 26. https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/open-energy-networks-project-energy-networks-australia-position-paper/

Figure 120 | Project EDGE roles and responsibilities



8.3.1 Management of power flows within secure limits

AEMO and DNSP roles can build on existing roles and responsibilities efficiently so DER operation remains within local and system limits as it scales

Project EDGE tested one of several potential arrangements possible under the OpEN Hybrid model.[340] As outlined above, Project EDGE arrangements leveraged existing frameworks, such as:

- AEMO's statutory function to manage power system security (including the safe scheduling and dispatch, and operation and control, of the national electricity system;
- DNSPs' management of the distribution network, with expanded roles, responsibilities and functions.

AEMO is currently responsible for maintaining power system security,[341] and would need to collaborate with DNSPs to be confident that power flows on the distribution network remain within secure limits and do not adversely impact transmission limits. Dynamic operating envelopes are a key tool to achieve this but there are also broader considerations to work through that are outlined below.

Local network limits considerations

DOEs, calculated and communicated by DNSPs, have been observed in Project EDGE field tests to efficiently bound DER operation within network and system limits (see 5.3.2.6). Flexible export limits, or emergency backstop mechanisms, are already applied to new PV installation in Queensland,[342] South Australia[343] and Western Australia.[344] The results discussed in chapters 2, 3, 4 and this chapter support a recommendation for DOEs (or at least initially, flexible export limits) to be rolled out to new PV installations as soon as practicable.[345]

It is important to consider how DOEs are introduced into the regulatory framework, as the NEM's legal and regulatory framework did not contemplate this operating design when it was written. If AEMO is responsible for whole of system security[346] and DNSPs are responsible for calculating and communicating operational limits to flexible resources, then existing provisions and obligations will likely need to be reviewed to ensure clarity in the allocation of roles and risk.

8.3.2 Wholesale dispatch conformance monitoring

Industry should further explore and resolve considerations on undefined aspects of VPP dispatch conformance monitoring

The approach to wholesale dispatch conformance monitoring of VPPs, and appropriate penalty mechanisms for non-compliance, are topics that will need to be defined through industry consultation.

As Project EDGE did not field test conformance monitoring options, the intention of this section is to support industry discussion to consider the broader capabilities and mechanisms that may be needed to integrate DER into the NEM.

As discussed in section 5.3.2.4, dispatch conformance in Project EDGE was assessed after the fact using trial data. The objective of the assessment was to simply observe whether aggregators' VPP telemetry (at a portfolio level) aligned with the dispatch instruction and if not, the average deviation and frequency of non-alignment. The results showed that while aggregators are generally able to conform to dispatch instructions, albeit inconsistently, there is nonetheless a need to monitor conformance and develop enforcement mechanisms because breaches occurring at greater volumes could adversely impact power system security.

340 AEMO and ENA. 2019, Open Energy Networks Interim Report: Required Capabilities and Recommended Actions. https://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

341 Clause 3.8.1 of the NER requires AEMO to operate a central dispatch process to balance power system supply and demand and use its reasonable endeavours to maintain power system security. Clause 3.8.10 provides that AEMO must determine and represent network constraints in dispatch.

342 Queensland Government. 2023, Emergency backstop mechanism. https://www.epw.qld.gov.au/about/initiatives/emergency-backstop-mechanism

343 Government of South Australia. N.d., Dynamic Export Limits Requirement, https://www.energymining.sa.gov.au/industry/modern-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes/dynamic-export-limits-requirement

344 Government of Western Australia, 2022, Information for Industry – Emergency Solar Management. https://www.wa.gov.au/organisation/energy-policy-wa/information-industry-emergency-solar-management#what-are-the-export-limits

345 The AER is currently reviewing the current regulatory framework in the NEM to develop policy advice on flexible export limit implementation within the NEM.

AER. 2022, Flexible Export Limits Issues Paper, p 2, Box 2. https://www.aer.gov.au/system/files/Flexible%20Exports%20-%20final%20Issues%20Paper_0.pdf

346 Clause 3.8.1 of the NER provides that AEMO is accountable for operating a central dispatch process that considers network constraints (both transmission and distribution).

Dispatch conformance for large-scale resources in the NEM comes with various tolerance bands, including a 6MW target deviation. Conformance monitoring is performed by AEMO, with non-conformance reported to the AER for compliance enforcement.[347] Further consideration needs to be given to whether it is appropriate for VPPs to have different, or the same, conformance monitoring processes and thresholds applied and the role of the AER in enforcement.

A current reform considering some of these questions is the Scheduled Lite rule change proposal.[348] The insights gained from Project EDGE and the VPP Demonstrations[349] informed the development of the proposed Scheduled Lite mechanism. The proposed compliance requirements in the Scheduled Lite mechanism were designed to balance recognition of the diverse capabilities of DER alongside defining appropriate obligations for reliable and secure participation in central dispatch.

Under the Scheduled Lite proposal, non-conformance would be identified in line with a guideline[350] (different to the strict accuracy levels outlined in the AEMO Dispatch Procedure[351]) that would determine how a non-conforming unit is managed in dispatch depending on the nature and impact of the non-conformance. This would require AEMO to receive telemetry data to monitor dispatch conformance.

To reliably manage power system security an additional and independent VPP dispatch conformance safeguard, a mechanism for independent measurement and potential control, should be considered. For example, this could currently be facilitated through meters, which are separate to the DER devices under control. In the event of a loss of control – either accidental or malicious (e.g. cyber-attack) – it may be possible for AEMO to instruct the DNSP or the metering coordinator to set the impacted meter(s) to a 'system emergency enforcing mode' and a default DOE or negative DOE (see section 5.3.2.7 and section 6.3.5.1) to effectively disconnect the no longer controlled load or generation, where this is available.

The use of meters in this manner would also need to consider controls to manage scenarios of communications loss with meters, which would result in the DNSP being unable to set the impacted meters to the system emergency enforcing mode. Consideration needs to be given to mechanisms that would enable the setting of this mode, such as thresholds that would trigger the setting of the emergency mode (e.g. if performance exceeded the most recently communicated DOE prior to the communications loss or performance was materially inconsistent with dispatch instructions after a set number of consecutive intervals) and the appropriate default settings to apply in these situations.

The independent conformance safeguard for VPP dispatch discussed above could also deliver enforcement actions as part of the to-be defined DOE conformance monitoring process, discussed below in section 8.3.4.4.

8.3.3 DOE conformance and compliance

DNSPs should be accountable for DOE conformance assessment. There may be a case for the AER to enforce compliance to address repeated breaches

As dynamic connection agreements are rolled out for new DER connections, DNSPs would be responsible for calculating and communicating the limits of their distribution networks to ensure DER operation remains within network limits at all times.

There will also need to be conformance monitoring and compliance processes to make sure that DOEs

347 AEMO. 2022, Dispatch, Appendix A. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705%20Dispatch.pdf

348 AEMC. 2023, Integrating price-responsive resources into the NEM. https://www.aemc.gov.au/rule-changes/scheduled-lite-mechanism

349 The VPP Demonstrations were a collaboration between AEMO, ARENA, AEMC, AER and members of the Distributed Energy Integration Program.

AEMO. N.d., Virtual Power Plant (VPP) Demonstrations. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations

350 AEMO. 2023, Electricity Rule Change Proposal: Scheduled Lite January 2023, p 30. https://www.aemc.gov.au/sites/default/files/2023-01/ERC0352_Rule%20Change%20Request_Scheduled%20Lite%20-%20including%20Appendix.pdf

351 AEMO. 2022, Dispatch, Appendix A. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705%20Dispatch.pdf

are adhered to. Given the importance of DOEs to the secure management of distribution level power flows and overarching power system security in a high DER future, it is vital that an effective compliance mechanism is in place.

Project EDGE did not implement and test a DOE conformance and compliance framework. However, DOE conformance results from the field tests (see section 5.3.2.6) identified a need for a robust framework. Discussions with project participants identified considerations for the roles and responsibilities that will need to be defined for AEMO, TNSPs and DNSPs, and aggregators with regard to DOE conformance monitoring and compliance. Industry should further explore the following considerations to evaluate consumer impacts and impacts to other operational and market processes.

DNSPs, or if efficient, metering coordinators on behalf of DNSPs, could be responsible for DOE conformance monitoring. However, as part of their responsibilities for calculating and communicating DOEs, DNSPs should be responsible for day-to-day DOE conformance assessment to ensure DER operation remains within safe network limits at all times.

Data received through smart metering (in Victoria at least) would enable this monitoring. Outside of Victoria, where NEM regions have lower penetration of smart metering infrastructures, DNSPs will need efficient access to data to enable DOE conformance monitoring.

DNSPs could be accountable for monitoring and could build the capability to do it themselves or explore the efficiency of outsourcing the monitoring (for example, to meter data providers or metering coordinators) and being alerted by exception when a breach occurs (based on pre-defined rules set by the DNSP). Once alerted, the DNSP could then assess conformance and decide on what to do (in line with the defined compliance framework). See section 5.3.2.7 for a discussion on some additional options that could be considered for DOE conformance monitoring.

If DOE non-conformance is identified at individual connection points that are not part of a VPP portfolio (i.e. DER is connected natively to receive the DOE from the DNSP), the DNSP will likely need to contact the customer directly to rectify the DOE non-conformance in accordance with the customer's connection agreement. If the root cause is an error on installation, the customer may need to contact the installer to apply the correct settings.

If the DOE non-conformance is identified to occur at multiple connection points associated with a VPP, then the DNSP will need to contact the aggregator to rectify the issue.

If non-conformance is identified as a persistent issue, a level of independence may be beneficial with regard to enforcement. It is also logical that to foster trust in the market for VPPs, a nationally consistent compliance framework is developed and managed by the AER, so that when DNSPs report repeated DOE non-conformance the AER is able to assess the data and transparently take appropriate action.

Accordingly, Project EDGE recommends that there should be three distinct roles relating to DOE conformance and that a separation of duties should be maintained between assessment and enforcement:

1. **DOE conformance monitoring:** Processing data to identify when a DOE breach occurs based on pre-defined rules – DNSP accountable with option to build capability or outsource responsibility
2. **DOE conformance assessment:** Using conformance monitoring results, assess whether the behaviour observed constitutes nonconformance that should be referred for compliance enforcement action – DNSP accountable with option to build capability or outsource responsibility
3. **DOE compliance enforcement:** Responsibilities of this role could include approving the measures that can be taken when a DOE breach is identified, and enacting the enforcement measure. For isolated breaches at individual customer premises, the DNSP may have delegation from the AER to enforce appropriate compliance mechanisms in line with the connection agreement. For more widespread non-conformance associated with an aggregator, the AER may be best placed to perform this compliance role but this will need to be defined by industry policy makers (along with all roles and responsibilities and associated processes related to DOE conformance and enforcement).

8.3.4 Considerations for VPP level DOE conformance and transmission constraints

AEMO, TNSPs and DNSPs will need to collaborate on further analysis to identify the most appropriate mechanisms to consider VPP level DOE conformance and impact on transmission constraints

As VPPs scale, portfolio level conformance to DOEs may be necessary. While VPPs are small, ex-post DOE monitoring and compliance measures may provide sufficient confidence that DOEs are being complied with across a VPP.

As VPPs reach material scale and start to participate in the wholesale dispatch process, the power system security risk posed by material DOE non-conformance increases. Accordingly, there may be a need for mechanisms to provide greater confidence (in real time) to AEMO and network service providers that VPPs participating at scale (in GWs) are operating within technical operational limits and are delivering services according to their dispatched quantities.

There are several potential approaches for consideration to provide AEMO, network service providers and the overall market confidence required to function efficiently. Some potential approaches may be used in combination, these include:

1. **Trust in self-constraining:** Trusting that aggregators are self-constraining in their wholesale bids, such that the dispatch of those bids will remain within any required limits with conformance assessed ex-post. This trust can be built through a track record of conformance and through knowledge that sufficient penalties for non-conformance can be applied in the event of a material breach of DOEs. Project EDGE tested this approach in the field trial.
2. **Coarse portfolio bid validation check:** Receive and validate for each 5-minute dispatch interval that aggregator wholesale bids are compliant with the sum of their NMI-level DOEs, and constrain down the dispatched quantity to the total DOE limit as required. Project EDGE tested this approach in the field trial.
3. **Transmission level constraint coordination:** Coordination between AEMO, DNSPs and TNSPs to define how much flexible generation or load can be dispatched through a given transmission node and applying the appropriate constraints in the dispatch process.
4. **Decentralised real-time monitoring:** A decentralised and autonomous approach using physical technology solutions (i.e. it could be in-front of, inside or behind the meter) that detect operational non-conformance and apply control settings to enforce conformance based on pre-defined rules.

The objective of the approaches considered is to provide AEMO, network service providers and the market a level of trust VPP portfolios are operating within technical limits and will be able to deliver according to their dispatch targets. A combination of the above approaches could also be applied – or variations of these approaches adopted – as required to provide this confidence.

The intention of this section is to support a discussion for industry to consider the broader capabilities and mechanisms that may be needed in a high DER future. The options discussed are not intended to be defined recommendations for industry.

The four potential approaches discussed in this section provide a spectrum of approaches that industry could consider and potentially explore further. Each approach would have implications for appropriate incentives and roles and responsibilities, as well as customer impacts. Accordingly, policy makers should work collaboratively with industry to understand the qualitative advantages and disadvantages of the various approaches to inform policy decisions on an appropriate framework and mechanism (or a combination of mechanisms) for VPP DOE conformance.

8.3.4.1 Trust in self-constraining (approach 1)

In this approach, aggregators submit wholesale bids in a way that is 'self-constrained'. That is, their VPP level bids of DER export will not exceed the total of all DOE export limits provided to them by the DNSP.

This approach was tested in Project EDGE during periods of Flex bidding as the real-time bid validation (approach 2, discussed below) cannot be applied where DOEs and VPP bids do not share the same definition of quantity (Net or Flex, see section 4.3.7 and section 5.3.2 for discussion). The trust in self-constraining mechanism proved effective but not 100% of the time (see section 5.3.2.4). At the GW scale being considered, the risk to system security from VPPs operating beyond operational limits would be materially higher; accordingly, there is a need for controls to manage this greater risk.

As observed in the field trial, aggregators may not always have the information or ability to self-constrain their bids to the limits.

There may also be instances where aggregators may have incentives to bid beyond the limits provided to them by the DNSPs if they consider the value from the wholesale market prices exceeds the potential costs of any ex-post enforcement or penalty.

Additionally, as discussed in the AoLR case study in section 5.3.2.6, in the field trial this meant conformance monitoring was limited to the DNSP performing DOE conformance analysis after the fact.

8.3.4.2 Real-time validation of bids (approach 2)

One approach tested in the field trial was for AEMO to perform a real-time validation upon receipt of bid files to check that the maximum quantity did not exceed the sum of NMI-level DOEs for that portfolio.

This means examining the aggregation of all site level DOEs (within a VPP) to check that the aggregate import and export limits are not exceeded by the maximum capacity bid by the aggregator for that DUID. To do this, AEMO needed visibility of the aggregated DOEs which it received from DNSPs via the DER data hub.

As this can be done before bid closure, AEMO would be able to constrain down a dispatch instruction quantity to ensure the VPP does not breach its sum of DOEs.

This represented a coarse validation, as a large proportion of the fleet would need to breach their DOEs for the VPP's aggregated DOEs to be breached. As discussed in section 5.3.2.4, this validation approach was tested in Project EDGE and the results identified that it was not a fail-safe solution because it would not prevent a large number of site-level breaches.

This validation would not be effective where an aggregator is receiving Net NMI DOEs and Flex bidding, as the sum of the DOE limits include uncontrolled load, which was observed to constrain Flex bids unnecessarily when this validation was applied for Flex bidding in the field trial. This validation had to be turned off in the field trial during Flex bidding as it unnecessarily constrained dispatch quantities.[352]

A further limitation of this approach is that it applies to individual VPPs individually. This means it does not ensure that if all aggregators under a given transmission node were dispatched within their DOEs that the transmission node limits would not be breached. This is risk is considered in approach 3 below.

8.3.4.3 Transmission level constraints and high scale DER coordination (approach 3)

Another mechanism for consideration is operational coordination between TNSPs, DNSPs and AEMO to define how much flexible generation or load can be dispatched through interface between the distribution and transmission networks (the 'transmission node'), and apply the appropriate constraints in the dispatch process.

Although transmission constraints were not a focus of Project EDGE (given the DER volume and scope restrictions of the project), they need to be addressed as VPPs reach a material scale across the NEM capable of impacting these constraints.

In the current central dispatch process, AEMO must apply the transmission constraints necessary to ensure the system always remains in a secure operating state. Currently, in the case of aggregators and their generation fleet (VPPs), transmission constraints do not apply. In a high DER future where multiple GWs of coordinated DER capacity are operated via aggregators, this could have an impact on transmission constraints at a given transmission node.

The wholesale market utilises Security Constrained Economic Dispatch (SCED) to maintain power flows within network limits.

In the case of distribution connected generators (the closest analogy to DER participating as scheduled resources), there is an added control whereby the generator is required to bid accurately within constraints communicated to them by the DNSP, such that the bid does not breach a constraint. Currently, the constraints are net at a transmission node;[353] that is, constraints are typically:

- Generators' target ≥ equal to or greater than the generators' initial value plus network flow (net) minus the network limit.[354]

352 Quantities were constrained because generally, a Net NMI DOE provides a smaller range since uncontrolled load erodes potential generation quantity. It could lead to a greater range, within which Flex bidding would fit, if the dispatch quantity was a load or if the aggregator did not have full control of rooftop PV and a battery was generating. For an aggregator, the most valuable configuration would be to control all generation in its portfolio.

353 AEMO. 2023, Constraint Formulation Guidelines, p 21, section 6.2. https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2023/constraint-formulation-guidelines-v12---final_1.pdf?la=en

354 For details on constraints, see Constraint Frequently Asked Questions - Constraint Results: Why do constraint equations bind?

AEMO. N.d., Constraint Frequently Asked Questions. https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/constraint-faq

This means AEMO does not have visibility of whether dispatching a given volume (MW) of participating DER generation under a particular transmission node will result in a breach of net transmission line flows at this point. Currently, with relatively low levels of participating DER generation this risk may not be high. However, the anticipated growth in coordinated DER means this risk will grow.

A potential solution (with limitations) is relying on approaches 1 or 2, as described above, or for TNSPs, DNSPs and AEMO to coordinate operationally (approach 3).

Under this approach, the existing NEM operational hierarchy of communications could apply – that is, AEMO to TNSP and DNSP, and back. TNSPs and DNSPs could provide dynamic information on how much flexible generation or load can be dispatched through a given transmission node. This independent data point could be used to inform the transmission node constraints applied in the central dispatch SCED, limiting all aggregator bids dispatched to being within the available transmission node capacity.

This would be an entirely separate data feed to the DOEs provided to aggregators, and would be data exchanged between AEMO, TNSPS and DNSPs. This data exchange could be facilitated by the DER data hub approach (see Chapter 6).

Alternatively, a by-product of Flex DOEs (discussed in section 4.3.7) could be the facilitation of this use case by summing the Flex DOEs allocated to each site (under that TNI). This would negate any requirement for DNSPs to provide a separate information stream to AEMO.

8.3.4.4 Decentralised monitoring (approach 4)

In this approach, decentralised refers to automated and autonomous monitoring through an on-site technology solution, such as metering equipment. This approach would monitor DOE conformance, and potentially compliance validation and enforcement, through a physical technology solution based on pre-defined rules.

This approach was not tested in the Project EDGE field trial but was contemplated in design workshops. Smart meters have the capability to do this today and are used as an example of how this approach could be implemented. In Victoria, where the field trial took place, smart meters are distribution network devices. Stakeholder discussions with non-Victorian distribution networks have noted new connections with DER would need smart meters to enable DOE capabilities. While smart meters were not used in Project EDGE for automated monitoring, they were used to provide data feeds for DOE conformance assessments.

Additionally, the AEMC's report on its review of the regulatory framework for metering services has recommended a target of universal (100%) uptake of smart meters by 2030 in NEM jurisdictions.[355] In making this recommendation, the AEMC notes achieving a 'critical mass' of consumers with smart meters can accelerate the provision of new and innovative services, as well as network benefits, that participating aggregators can pass through to electricity consumers.

Considering the adoption of this recommended policy direction would result in wide-spread installation of smart meters. One way in which this decentralised approach could operate includes using smart meters in the following manner:

- Additional controllable elements in smart meters (up to three in total) could be utilised: one to separate generating DER (solar and batteries), one to separate controlled loads (potentially EVs and other assets) and one to separate the customer's essential electrical service (so that it is not curtailed).
- Under normal power system conditions, the smart meter could be set to a 'permissive' mode where it receives a DOE, measures compliance at high sampling frequency at the meter and sends an alert to the DNSP when power flow is non-compliant. The meters could also have a configuration to send high frequency reads when a non-compliant alert is triggered.

Additionally, if no DOE is received by the meter, the smart meter could have default setpoint settings enabled during installation to measure conformance against the default limits defined by the DNSP as compensatory controls should DOE data exchange fail (as discussed in section 6.3.5).

Project EDGE tested the use of default limits, and overall field test results showed the control generally worked as intended. However, this was tested in Project EDGE through the implementation of default limits within the

355 AEMC. 2023, Review of the regulatory framework for metering services. https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_metering_review_-_final_report.pdf

aggregators' systems and hardware rather than smart meters. There were limitations with this approach. If the aggregator were to lose communications with its devices, regardless of whether it had implemented the default limit, the aggregator would not be able to communicate with the devices to identify if they were operating within safe conditions. This indicates that capabilities need to be within the site (e.g. smart meters) to mitigate risks associated with a loss of communications.

Under emergency system conditions, the smart meter could be set to an 'enforcing' mode where it operates similar to the permissive mode but with the opening of the generation or controlled load contactor (disconnecting it from the main power grid). Protections could include an inverse time delay adopted from over-current protection. The mode could also have a timeout period after which it would revert back to permissive mode if no further instructions were received.

Under this approach, essential load would be protected because it would be isolated from the other DER generation and load power flows that could be switched off. As noted in the introduction to this section, other customer protection considerations should be explored if this approach is progressed by policy makers.

As this process would occur after the start of a dispatch interval, some breaches could occur. However, DNSPs and AEMO would have confidence that material breaches would not occur because settings of the automated disconnection process could be proportional, responsive and targeted. The process could also comprise a feedback loop between DNSPs and AEMO and be complemented by the provision of portfolio telemetry data from aggregators. The portfolio telemetry data would provide AEMO with visibility of how the aggregator is progressing toward conforming with the dispatch targets.

The actions decided upon should form part of a defined DOE conformance monitoring and enforcement process that would allow DNSPs to take the necessary actions discussed. AEMO could follow its dispatch conformance process[356] to restrict bids from the aggregator until AEMO had confidence the portfolio was back to operating within constraints. This could entail coordination between the control rooms of AEMO, the DNSPs and the affected aggregators.

A by-product of this approach is it could feed into a DOE reallocation process. Sites within the restricted portfolio would not be utilising their allocated DOEs since the automated disconnection process would prevent those sites from exporting. This could allow DNSPs to increase the DOEs for distribution network customers outside of the restricted portfolio.

8.3.4.5 Next steps for exploring these considerations

These approaches would give AEMO and DNSPs varying degrees of confidence that distribution level constraints are not being materially breached during each 5-minute dispatch interval.

Several elements require further exploration for each of these considerations, including detailed roles and responsibilities, implementation factors, customer impacts and protections, and incentives for participants. Policy makers should work closely with market bodies and industry to consider the benefits and implications of each approach and leverage recommendations on smart meters from the AEMC's review of the regulatory framework for metering services where relevant.[357]

8.3.5 DER registration for services

Both AEMO and DNSPs are responsible for registering VPP portfolios (for wholesale and NSS services respectively); coordination is needed, and common infrastructure could avoid duplication and mitigate risk of errors

Both AEMO and DNSPs will need to register VPPs to deliver either wholesale or local network support services. Each entity should develop an efficient and scalable registration process that:

- Includes robust but efficient testing and pre-approval processes to deliver services
- Enables automated portfolio updates and approvals to add and remove connection points and DER with the same technologies that are in the registered portfolio
- Considers enabling registrations and portfolio updates for increments less than 1MW, particularly for local network services but also for wholesale services

356 AEMO. 2022 Dispatch, Appendix A, section A.3. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705%20Dispatch.pdf

357 AEMC. 2023, Review of the regulatory framework for metering services. https://www.aemc.gov.au/sites/default/files/2023-08/emo0040_-_metering_review_-_final_report.pdf

- Coordinates new site market enrolment activation dates with DOE receipt (discussed in section 5.3.2.6).

In Project EDGE, a single source of truth (via the DER data hub) was referenced by AEMO and AusNet. This approach avoided the duplication of registers that currently occurs whereby DER standing data is replicated across multiple, independent systems.[358]

If each party were to maintain a different portfolio management system for VPPs (AEMO for wholesale, DNSPs for local network services and aggregators for internal portfolio management), it could create inefficiencies and raise risk of errors and disputes. It would also not be scalable in a high DER future.[359] While processes could be implemented to transfer data among these systems, it would not eliminate the risk of discrepancies arising over time.

A more efficient and robust approach would enable AEMO, DNSPs and aggregators to access a single, integrated system that records customer consent and allocation of DER into VPP portfolios, as well as participation of DER within different VPP portfolios to deliver different electricity services.

8.3.6 Service co-optimisation roles and responsibilities

Aggregators are best placed to co-optimise DER for delivering multiple services

In the early design stages of Project EDGE, several theoretical options for NEM-wide optimisation including DER activity at wholesale and local levels were explored:

- Aggregator co-optimisation whereby the aggregator receives all external signals (prices and constraints) and optimises DER portfolio value on behalf of customers (the approach tested and implemented by Project EDGE)
- The DNSP offers prices for alternative DOEs to forecast distribution network constraints
- Tri-optimisation between energy arbitrage, FCAS and local network services (with three separate bids)
- NMI-level bid and dispatch.

These options were workshopped within the project team and with stakeholders in industry forums. Compared to the three other alternatives considered, aggregator co-optimisation has several advantages:

- Risks and incentives for co-optimisation lie with aggregators, the party best able to economically optimise their customers' DER on their behalf
- Streamlined bidding with all service capacity for a portfolio represented in one bid file
- Potential for value stacking, providing incentives for active DER uptake
- Likely more cost efficient through simplicity, as capability can be developed as part of the aggregator's business model. Additionally, no extension to current roles in the NER framework would be required, compared with a framework prescribed through regulatory and system changes that establish preference for one type of service over another, and the associated functions that would need to be built by AEMO or another party to perform this co-optimisation.

Performance in the field trial confirmed aggregators were able co-optimise local and wholesale energy services. The aggregators participating in LSE events were able to meet wholesale dispatch targets while simultaneously delivering local NSS. This involved ensuring their wholesale market bids and offers were submitted in a way that NSS contractual obligations would be included in the wholesale dispatch targets provided by AEMO (see discussion on value stacking in section 5.3.2.9).

The independent CBA found that the aggregator role is a primary driver of the value identified in the CBA.

358 EY. 2023, Project EDGE: Technology and Cybersecurity Assessment May 2023, p 21, section 3.1. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

359 EY. 2023, Project EDGE: Technology and Cybersecurity Assessment May 2023, p 108, Appendix A. https://aemo.com.au/-/media/files/initiatives/der/2023/project-edge-technology-and-cybersecurity-assessment-final.pdf?la=en

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Roles and responsibilities for optimisation of DER

Project EDGE found that aggregators are best placed to co-optimise services they can provide, as their key objective is to deliver customer value while supporting their own commercial interests.

8.3.7 Operation of digital solutions to facilitate DER data exchange and local network support services procurement

Two major steps remain in defining DER integration roles and responsibilities: agreeing who should operate a DER data hub (if implemented) and, separately, who should operate digital solutions for DNSPs to procure local network services

Project EDGE has produced a practical and economic evidence base that supports the case for a NEM DER data hub. If a process is established to consult broadly on the case for a NEM DER data hub, it will need to address a number of design questions regarding who should own, govern, operate, develop/update and recover costs for a NEM DER data hub.

The agreed direction on these design principles will then determine whether responsibilities are centralised with AEMO, shared amongst key industry participants (such as DNSPs) or allocated in alternative arrangements.

If a DER data hub is not established, then the digital solutions for DER data exchange will evolve organically with DNSPs developing separate systems to communicate DOEs. Retailers may choose to develop and operate similar solutions to communicate dynamic export limits or use DNSP operated solutions.

Similarly, design choices on how to standardise the trade of local NSS will determine the operational responsibilities for digital solutions that facilitate the trade of these services.

Project EDGE explored a model whereby DNSPs retain the responsibility to manage a digital solution to procure local NSS, but that system is connected to a DER data hub to enable standardised data exchange. In this scenario, DNSPs could equally choose to engage (either individually or in collaboration with other DNSPs) an independent party to operate a digital solution that they use to procure local NSS (such as NODES[360] in the UK and Norway, see the case study in section 7.3.1).

Decisions on who should operate digital solutions for DER data exchange and local NSS procurement are the two last major steps in defining DER integration roles and responsibilities.

8.3.8 The CBA found that Project EDGE's arrangement of roles and the responsibilities is aligned with the NEO and promotes efficiency

Project EDGE's arrangement of roles and responsibilities features DER aggregators optimising customer assets against all limit and price signals as the key driver of benefits from the coordination and integration of active DER into the NEM

As part of the independent CBA for Project EDGE, Deloitte Access Economics evaluated the ability of the roles and responsibilities arrangements to deliver economic value through techno-economic modelling and Multi Criteria Analysis of those tested in Project EDGE, as well as alternative arrangements within the Hybrid framework.[361]

The CBA found the Project EDGE arrangement of roles and responsibilities underpins the realisation of benefits identified in the CBA from the accelerated and optimised integration of active DER into the NEM.

360 NODES. 2023, Flexibility. https://nodesmarket.com/flexibility/

361 Deloitte. 2023, Project EDGE CBA Final Report, p.64. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

Having DER aggregators receive the necessary external signals (such as prices and constraints) and co-optimise DER portfolios across wholesale and B2B opportunities (e.g. network support services) on behalf of DER consumers allows:

- Prioritisation of DER consumer interests in how their DER is utilised – this is particularly important in a voluntary arrangement where consumers who have invested in DER need to perceive clear value in participating in the NEM through a DER aggregator
- Streamlined bidding with all service capacity of a portfolio represented in a common fleet level bid to the market operator
- Opportunities for value stacking, which can allow for greater customer offerings and cost efficiencies to be realised by DER aggregators
- An appropriate allocation of risks and incentives as DER aggregators are responsible for optimising DER while acting in compliance with market rules and connection agreements.

Further, assessment of other key functions such as data accessibility, settlement support for network services and connecting DER showed the Project EDGE arrangement:

- Delivers value to customers through reduced complexity
- Supports efficiency via the provision of information to enable competition and flexibility over time (e.g. the provision of up-to-date DER information from market participants and switching of DER aggregators)
- Ensures an appropriate allocation of risk such that market participants who are best positioned to manage specific risks do so.

The Project EDGE arrangement of roles and responsibilities also broadly aligns to the NEO and promotes efficiency with the principle of extending current roles and responsibilities rather than creating new ones or duplicating existing ones.

8.4 Key insights and implications for industry

Project EDGE identified that existing roles and responsibilities could be expanded to progress and maintain the integration of DER into the power system and electricity markets.

Project EDGE notes the following key insights and implications for industry.

For policy makers

- Consider a review of the NEM's legal and regulatory framework to ensure clarity of roles and responsibilities and risk allocation if DNSPs are calculating distribution constraints while AEMO is responsible for maintaining system security.
- Consider developing and implementing a robust DOE conformance monitoring and compliance framework that separates duties in terms of DOE conformance monitoring, DOE conformance assessment and DOE compliance enforcement.
- If a common industry data exchange infrastructure is deemed suitable for DER, consider design principles and policy objectives to determine who should be responsible for operating and governing the digital solutions that support this.

For AEMO

- Further consider approaches and mechanisms for VPP level DOE conformance monitoring and the management of transmission level constraints in a high DER future where VPPs reach material scale across a state and a concentration of resources in a particular area may impact transmission constraints at certain times.
- Note the results of the Project EDGE field trial, which showed that AEMO does not need to be responsible for co-optimising DER services in a future system where DER are integrated into electricity markets. AEMO can continue to co-optimise wholesale services dispatch (energy and FCAS). Aggregators are best placed to co-optimise DER services (such as providing wholesale services while simultaneously delivering local network services).

For DNSPs

- Collaborate with policy makers and AEMO to develop a DOE conformance and compliance framework.
- Participate in the exploration of approaches and mechanisms for VPP level DOE conformance monitoring that provide AEMO with confidence it can dispatch aggregator bids that will not materially impact distribution network limits.

For aggregators

- Note the results of the Project EDGE field trial, which showed that in a future system where DER are integrated into electricity markets, aggregators are best placed and able to co-optimise DER services (such as providing wholesale services while simultaneously delivering local network services).

DNSP INVESTMENT AND CAPABILITY DEVELOPMENT

This chapter focuses on the research question:

How could DNSP investment to develop DSO capabilities improve the economic efficiency of integrating DER into the NEM?

Overview
• DNSPs have a key role in facilitating DER integration into the power system and electricity markets.
• The Deloitte Access Economics CBA found that implementing DOEs to unlock network capacity is a prime value enabler of DER, with greater customer coverage providing greater benefits. This is a compelling justification for DNSPs to develop appropriate capabilities to transition to dynamic connection agreements and DOEs for all new DER connections.
• Practical experience and stakeholder engagement as part of Project EDGE identified multiple capabilities that need to be developed to support the transition to DOEs. These capabilities relate to: - Planning – developing planning and forecasting capabilities to support DER integration, including identifying opportunities for DNSP expenditure on NSS and network development - Connections – developing new dynamic connection agreements, streamlining and/or automating the connections process for DER and developing new tariff arrangements - Operations – improving the monitoring and visibility capabilities required for hosting capacity assessment and calculation of DOEs, developing LV network models and developing capabilities to calculate, communicate and assess conformance to DOEs - Data sharing – moving progressively toward more advanced data sharing capabilities.
• Industry also needs to consider the capabilities required to support standardised procurement of NSS, including identifying and communicating detailed data on the forecast needs for NSS, potentially operating digital solutions such as a Local Services Exchange (LSE), integrating NSS with traditional network operations and operational coordination with AEMO
• Regulatory incentives to facilitate the development of DSO capabilities by DNSPs may need to be strengthened to support the integration and coordination of DER in the NEM. The UK experience suggests that, in addition to defining the roles and responsibilities of DSOs in the NEM, there may be a need for specific regulatory incentives in Australia so that DNSPs develop the right capabilities at the right time to enable the efficient transition to net zero in the NEM.
• UoM's research for Project EDGE found that significant value can be unlocked for a voltage constrained distribution network through voltage management services. Consideration needs to be given to developing DNSP voltage management service capabilities – and supporting regulations – to unlock market value and drive efficient market outcomes.
• Industry collaboration will be important to identify a consistent definition of what DSO capabilities are required in Australia and trigger points for when they are needed.
• When defining the role of DSOs and the extent to which they can support efficient market outcomes, policy makers should consider the role of DNSPs in moving beyond efficiently managing the physical network infrastructure to also facilitating broader efficiency outcomes, including how flexible capacity in network infrastructure can deliver savings for all consumers.
• Once the DSO role and responsibilities are defined, a review of regulatory incentives could be considered to evaluate whether current incentives are appropriate, and simple to navigate, to support the implementation of defined DSO capabilities. In undertaking the review, consideration should be given to the growing need for flexibility across the power system to enable Australia's energy transition.

9.1 Context

With the anticipated scale of DER projected to exceed 100GW by 2050 (see section 1.2.2), DNSPs have a key role in facilitating DER integration into both the power system and electricity markets, as discussed in Chapter 8.

The extent to which DER can participate in and provide services to the system and electricity markets is related to the extent to which the distribution network to which they are connected can allocate spare network hosting capacity (see Chapter 5).

Therefore, as the integration of DER relates to both wholesale and local NSS, this research question could equally be articulated to align to the NEO as 'how could DNSP investment to develop DSO capabilities support efficient investment in, and operation and use of, electricity services for the long-term interests of consumers?'.

However, as discussed in section 5.3, developing capabilities to improve network hosting capacity requires time and investment. Sufficient incentives and policy directions are needed for DNSPs to invest in the capabilities required to maximise the efficient use of DER for the benefit of all consumers.

9.2 Approach

To answer this research question, Project EDGE completed several activities, including:

- UoM was engaged to undertake techno-economic modelling and DOE research. The purpose of this research was to identify how the design and allocation of DOEs could impact the efficiency of DOEs and therefore the amount of network hosting capacity that could be allocated to DER to provide services. Additionally UoM developed use cases for market facilitation and network support analysis to understand whether DSO capabilities could provide value in terms of network and system efficiency.
- Deloitte Access Economics was engaged to undertake a CBA to evaluate the benefits that dynamic connection agreements and flexible export limits could provide to the system and all consumers in line with the NEO.
- Field test data was used to undertake theoretical desktop analysis to compare UoM's findings on DOE design and allocation. This research and analysis was used to further understand the value that DOEs could provide in terms of facilitating DER providing services.
- Stakeholder engagement with AusNet services and other DNSPs identified key DSO-related capabilities that are required to unlock the benefits identified in the CBA.

The insights from these various research activities collectively indicate whether DSO capabilities could be considered an efficient investment in electricity services that provide benefits to the system and all consumers.

9.3 Findings

This section summarises the key findings on DNSP investment and capability from Project EDGE's research and field trial activities.

9.3.1 DNSP capability investment and development for the DOE transition

DNSPs need to invest in technical and non-technical capabilities to support the transition to flexible exports

The Deloitte Access Economics CBA found implementing DOEs to unlock network capacity is a prime value driver of DER, with greater customer coverage providing greater benefits (see section 3.3.1).[362]

This is a compelling justification for DNSPs to develop appropriate capabilities to transition to dynamic connection agreements and DOEs for all new DER connections. Industry has identified the need for such an approach through the DOE workstream of the Distributed Energy Integration Program, which is supported by the CBA findings regarding customer coverage being a prime value driver.[363] Continuing the effort to adopt a national approach to DOE implementation should also enable a smoother implementation.

362 Deloitte Access Economics. 2023, Project EDGE CBA Final Report, Executive Summary, p 21. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

363 ARENA. 2022, Dynamic Operating Envelopes Workstream. https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/

Practical experience and stakeholder engagement as part of Project EDGE has identified multiple capabilities that need to be developed to support DOE implementation. These capabilities are linked to those in the DOE roadmap (Figure 47, section 4.3.8), and include:

Planning

- Developing planning and forecasting capabilities to support DNSP expenditure for DER integration aligned to AER guidance:[364]
  - Identifying current and forecast DER penetration, sizes and potential unconstrainted exports
  - Identifying current and forecast network hosting capacity, together with the amount and timing of expected DER curtailment
  - Identifying the impact of potential expenditure on reducing DER curtailment and the value of associated initiatives. This relates to the customer export curtailment value methodology.[365]
- Developing visual tools to show forecast constrained parts of the network where DOEs may be used more (relating to export constraints) and unconstrained areas that may be more suitable for EV charging.

Connections

- Developing new dynamic connection agreements and streamlining and/or automating the connections process for DER (including new rooftop PV or EV chargers) to process expected big increases in applications:
  - To facilitate interoperability and improved visibility of connecting DER, industry should consider how to enable 'plug and play' functionality that supports automated device discovery at the time of connection. See section 6.3.2 for a discussion on how a DER data hub could support this use case.
  - Critical to the adoption of new dynamic connection agreements is customer willingness to enter into such agreements. This will require DNSPs to develop existing customer engagement and information sharing capabilities so that customers have access to simple to understand information about the implications and benefits of dynamic connection agreements. Without customers willing to enter into dynamic connection agreements, the benefits of DER integration discussed throughout this report cannot be realised. The fundamental role customers will play in the integration of DER is discussed in Chapter 2. As discussed in that chapter, industry needs to build customer trust and knowledge about the benefits to DER customers and all consumers of participating in VPPs.
- Developing new tariffs arrangements to encourage changes in behaviour, potentially including time-of-use tariffs, export tariffs or dynamic network pricing and other innovative tariffs (if through trials they are shown to be effective and feasible).

Operations

- Improving monitoring and visibility capabilities required for hosting capacity assessment and calculation of DOEs:
  - UoM found that DNSPs in Australia have significant diversity in terms of their available infrastructure and data, which means each DNSP will need to consider different DOE implementation approaches.[366]
  - The most advanced and accurate DOEs require a full electrical LV network model and full monitoring of the distribution network's customers.
  - These models require several inputs, including forecast voltage magnitude at the head of the LV feeder, net demand of passive customers (active and reactive power and net demand of active customers (reactive power).
  - However, not all networks may be able to develop the capabilities to implement such DOEs. UoM found that DNSPs with limited monitoring may also be able to implement simpler DOEs that can work relatively well. The inputs for such DOEs include forecast and historical active power, historical voltage magnitude at the distribution transformer and historical voltage magnitude at the customers most affected by voltage variations of the LV network.
  - UoM's work suggests that full electrical LV network models and full monitoring capabilities may not be needed immediately by all DNSPs to calculate DOEs that alleviate network constraints. However, all DNSPs will need to improve their forecasting capabilities to be prepared for the forecast increase in DER .

364 AER. 2022, Distributed energy resource integration expenditure guidance note. https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distributed-energy-resources-integration-expenditure-guidance-note/final-decision

365 AER. 2022, Customer export curtailment value methodology. https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/customer-export-curtailment-value-methodology/final-decision

366 Gonçalves Givisiez A, Ochoa L, Liu M, Bassi V. Assessing the Pros and Cons of Different Operating Envelopes Implementations across Australia, CIRED 2023, Rome, Italy, June 2023. https://www.researchgate.net/publication/371686444_Assessing_the_Pros_and_Cons_of_Different_Operating_Envelopes_Implementations_Across_Australia

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Considerations for DNSPs on DOE approaches

As discussed in section 4.3.2, even implementing simple DOE approaches should realise value when compared with retaining static connection agreements. However, as DER penetration increases, the improved network hosting capacity provided by more accurate LV network model DOEs, compared with simpler approximation or estimation DOEs, means that all DNSPs should consider progressively investing in capabilities to develop LV network models.

- Improving head of feeder voltage forecasts (as discussed in section 4.3.5.1) as a priority for DNSPs investing in developing full electrical LV network models
- Developing capabilities to calculate DOEs and DNPs (if through trials they are shown to be effective and feasible), including operational forecasting and network state estimation capabilities, which need sufficient monitoring capabilities to be delivered
- Developing capabilities to communicate DOEs, either directly to DER/DER operators or via integration with a DER data hub if progressed
- Integrating DNSP operational planning processes with DOE processes
- Developing capabilities to assess conformance to DOEs, including defined performance thresholds (see section 4.3.5).

Data sharing

- Sharing DOE data (including non-conformance) with TNSPs, AEMO and market bodies. AEMO would need DOE forecasts for visibility and related data for coordination of enrolment processes. Additionally, a DOE compliance enforcement body would need to see the non-conformance data and assessments (see section 5.3.2.6 for a discussion on the need for a DOE conformance assessment and enforcement framework)
- Publishing information on DOEs, including estimates for the value of DER constrained times (e.g. energy constrained times that coincide with wholesale price). These should be historical and forecast values:
  - Since DOEs improve existing spare network hosting capacity (but do not actually increase overall network hosting capacity), they are a more accurate approach for sharing of existing network capacity. But that means that, as DER penetration increases, DER constraints will continue to increase. As such, publishing DOEs would provide transparency on the constraint time and value as a pre-cursor to trigger further network investments. Industry should consider the appropriate mechanisms through with DOEs could be published.

As recommended in 5.3.2, DNSPs should start simply and progress toward more advanced capabilities in a targeted approach over time. Different DNSPs will need to progress and develop these capabilities at different rates, depending on specific factors in their network (e.g. DER penetration, availability of data, network condition/capacity). Conducting CBA feasibility assessments can also provide the AER with confidence that investments are prudent and efficient.

9.3.2 Capabilities required to support standardised procurement of network support services

Industry should consider the capabilities required to support standardised procurement of NSS subject to the framework adopted

As DER scales in each DNSP service area, the opportunity to utilise DER flexibility for NSS from DER will also grow. Developing an LSE is not the only option available to DNSPs to utilise DER flexibility for NSS. Other demand response mechanisms such as DNPs could also be effective.

If industry proceeds with an LSE framework to standardise procurement of network support services, DNSPs will need to develop further DSO capabilities associated with procuring and coordinating NSS from DER, including:

- Identifying and communicating detailed data on the forecast needs for NSS through annual planning reports, demand side participation information[367] and supplementary mapping tools, with the potential to evolve to more frequently updates
- Procuring NSS that are defined using standardised characteristics and transacted in a standardised way
- Potentially operating (or outsourcing) digital solutions such as LSEs (see section 7.3.1) or 'flexibility' exchanges to facilitate more efficient procurement as the need scales. Depending on the approach adopted for procuring services, this could involve augmenting capabilities to:
  - Enrol / onboard DER aggregators to deliver services, including pre-qualification testing
  - Engage network support services provider through new types of digital contracts
  - Dispatch resources to pre-arm or deliver network support services
  - Verify and settle transactions through automated analysis of verification data and authorisation to settle payments
- Integrating the triggering of NSS with traditional network operations that can automate the dispatch signals in response to conditions observed on the network through monitoring capabilities or directly from control room operators
- Operational coordination with AEMO. As discussed in section 5.3.2.9, aggregators should reflect capacity committed to all services in their forecasts and bids and offers provided to AEMO. However, there will likely be scenarios where NSS are being provided by the aggregator but the aggregator is not providing forecasts to AEMO (for example, the DER capacity of their portfolio is not of a material size that requires it). To account for such scenarios, a mechanism may be needed for AEMO to obtain that visibility.

The capabilities in which DNSPs would need to invest would depend on the LSE approach adopted by industry.

Additionally, in making the investment decisions to invest in developing these capabilities, DNSPs will need to align with the regulatory economic framework overseen by the AER.

9.3.3 Regulatory incentives

Regulatory incentives may need to be reviewed and strengthened to support development of DSO capabilities

Project EDGE did not comprehensively evaluate the regulatory incentives needed to facilitate the development of DSO capabilities by DNSPs. However, the required capabilities, as discussed in this chapter, would need significant investment over time. Some of these capabilities were identified and explored through Project EDGE's research, including UoM's research on DOE design (see section 4.3.1) and the theoretical desktop study, using field test data, of different DOE permutations (see section 4.3.4).

As discussed in several places throughout this report, investments to facilitate the integration and coordination of DER in the NEM need to occur rapidly. The CBA for Project EDGE recommended that investments to integrate DER be made as soon as possible to realise the whole-of-system benefits to all consumers.

Accordingly, Project EDGE:

- Undertook a literature review of case studies to show how regulatory incentives can facilitate the development of DSO capabilities and to identify existing regulatory incentives available to DNSPs
- Engaged UoM to conduct research to understand the potential value voltage management services could provide to DNSPs in managing voltage issues and to aggregators by unlocking potential market value.

The following case study from the UK outlines some considerations for policy makers and industry regarding the role of regulatory incentives in enabling DNSPs to develop DSO capabilities.

Australia has an opportunity to learn from the experiences in the UK and achieve a level of standardisation suitable for NEM participants before NSS trade scales up.

367 AEMO. N.d., Demand Side Participation Information Guidelines. https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-plaN.nning-guidelines/demand-side-participation-information-guidelines

CASE STUDY

Literature review – UK regulatory incentives for DNOs

This case study discusses regulatory incentives in the UK for distribution network operators (DNOs) to develop DSO capabilities in the next five years.

Context

The UK is experiencing a rapid uptake of EVs which, together with broader electrification, is pushing up peak demand levels. Industry leaders have emphasised the need for flexibility services (referred to as network support services in the Australian context) at both wholesale and distribution levels to support the nation's net zero transition. In the final determinations for RIIO-ED2, Ofgem has included a range of regulatory incentives for DNOs to develop DSO capabilities in the 2023-2028 regulatory period. These initiatives have broad support across the energy industry.[368]

Ofgem DSO regulatory incentives

Regulatory incentives include:

- A new DSO financial output delivery incentive (ODI-F) to drive DNOs to more efficiently develop and use their networks, including considering flexible and smart alternatives to defer the need for reinforcement and ultimately reduce customer bills
- Funding to improve the DNOs' monitoring of their networks
- New licence requirements for all DNOs to ensure that they communicate flexibility requirements for the future
- A new licence obligation (LO), which requires DNOs to enable system optimisation through collaborating with stakeholders and creating a forward-looking, open and interoperable digital network mapping platform.

New data and digitalisation LOs will also deliver significant improvements in data availability, coordination and transparency.

Load Related Expenditure (LRE)

Ofgem have set an expectation that DNOs use 'flexibility in the first instance before considering traditional network investment'. Ofgem have set annual LRE allowances[369] that are 40% higher than in RIIO-ED1 and a circa 95% increase on actual load-related spend in RIIO-ED1.

Potential opportunities in the NEM

There is strong regulatory support in the UK for DNOs to invest in DSO capabilities that will support a smarter and more efficient UK grid. There is an opportunity for similar coordinated action in the NEM to support the definition and implementation of DSO capabilities that DNSPs must develop in the Australian context.

As discussed in section 8.1, the roles and responsibilities of a DSO as a key actor needed to integrate DER in the NEM are yet to be fully defined in Australia, notwithstanding the term exists in the NER. The UK experience shows that, in addition to defining the roles and responsibilities of DSOs in the NEM, there may also be a need for specific regulatory incentives in Australia so that DNSPs develop the right capabilities at the right time to enable the efficient transition to net zero in the NEM.

Industry coordination will be important to identify a consistent definition of what DSO capabilities are required in Australia and trigger points for when they are needed. Industry coordination could also support the consistent and efficient development of these capabilities.

368 Ofgem. N.d., RIIO-ED2 Final Determinations. https://www.ofgem.gov.uk/publications/riio-ed2-final-determinations

369 Flexibility allowances are calculated in relation to deferred secondary reinforcement in substations and/or circuits, using the following formula:: Reinforcement deferred (MVA) * £/MVA unit cost for GMT * WACC^contract length.

9.3.4 Voltage management

Consideration needs to be given to developing DNSP voltage management service capabilities to unlock market value and support efficent market outcomes

Project EDGE's research and analysis to inform how DNSPs could develop further capabilities to support more efficient wholesale market outcomes included research from UoM exploring how DNSPS could facilitate wholesale energy services and NSS.[370]

UoM's research found significant value can be unlocked for a voltage constrained distribution network through voltage management services.[371] Simple but aggressive Volt-VAr curves[372] applied by participating inverters can unlock hosting capacity in voltage constrained networks (see section 7.3.2.5 for a discussion on field test results showing that two aggregators in the Project EDGE field trial were able to technically provide voltage management services). As such, voltage management services not only unlock opportunities for DNSPs to utilise DER flexibility for network management; they also open additional revenue streams for DER.

However, the net benefits of providing voltage management services are highly sensitive to wholesale spot market prices. When spot market prices are high, the benefits of using voltage management are expanded as the export capacity of the distribution network is greater, releasing higher value solar power even if this results in high electrical losses during the process.

Additionally, the location of DER impacts the value it can provide. Resources closer to the head of the feeder are more valuable for active power network services. Resources at the network fringe are more valuable for reactive power dispatch to manage network voltages.

This aligns with an objective function that allocates spare network hosting capacity based on its most efficient allocation, rather than using concepts of fairness. As discussed in section 4.3.2, DOEs with the objective function of increasing system technical and economic efficiency are likely to provide the most benefits to all electricity consumers in the NEM and could be considered to maximise fairness from a whole-of-system perspective. This aligns to the principles of efficiency for the long-term interests of all consumers in the NEO.

To unlock this market value through voltage management, UoM's research also found DNSPs could implement network solutions, such as voltage control at zone sub-stations to facilitate better market outcomes;[373] for example, proactively lowering the supply voltage when market prices signal a need more generation/exports. UoM also found that both active and reactive power procurement have the potential to unlock value for the network.[374]

In 2020, United Energy demonstrated in practice how a dynamic voltage management system across 47 zone substations could reduce voltage by 3% on average to deliver at least 30MW of demand response within 10 minutes when called upon, sustained for four hours.[375]

Regulations around how such tools could and should be operated would need careful consideration. One consideration is the opportunity this practice could provide to enhance the management of Minimum System Load (MSL) and Lack of Reserve (LoR), potentially avoiding last-resort curtailment in some cases. For instance, DNSP voltage management could be activated if market notices from AEMO do not yield a market response to the forecast system conditions.

370 S. Riaz, J. Naughton, UOM. 2023, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches. In press.

371 S. Riaz, J. Naughton, UOM. 2023, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches, p.3. In press.

372 VAr is the measuring unit for reactive power. Voltage can be managed via a Volt-VAr curve. It is either the injection or absorption of reactive power. The combination of a configurable array of points define a linear curve that results in the desired Volt-VAr behaviour.

373 S. Riaz, J. Naughton, UOM. 2023, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches. In press.

374 Active power is 'useful' actual or real power used in the circuit. Whereas reactive power bounces back and forth between the load and source. Reactive power helps produce magnetic and electric field and stores in the circuits and can be discharged by transformers.

375 United Energy. 2020, United Energy Demand Response – Final Project Performance Report. https://arena.gov.au/assets/2021/02/united-energy-demand-response-final-project-performance-report.pdf

Policy makers should consider the effect on market efficiency and confidence that such practices from regulated monopolies would have. This would need to be considered in the context of other potential non-market solutions that could be deployed before last-resort curtailment of customer load or solar. Examples include NSS[376] (see Chapter 7), RERT ,[373] utilising the DOE framework or market directions to aggregators discussed in section 5.3.2.8 – although the options discussed in this report are by no means exhaustive.

While voltage management has been demonstrated to be effective in delivering services, Victorian DNSPs have shown that ongoing reductions in voltage (following action from the Victorian Government) are estimated to have resulted in $7m in savings per annum for all Victorian customers due to electricity consumption savings that result from supply voltages being closer to 230 volts.[378] This evidence base could inform a broader movement to reduce voltage levels across distribution networks to deliver ongoing savings for all consumers.

Another example of dynamic voltage management being deployed to a greater extent is in the UK where Ofgem has allowed[379] distribution networks to use voltage control technologies to participate in competitive balancing markets.[380] This is summarised in the following case study.

CASE STUDY

Literature review – UK Ofgem decision to allow DNOs to provide CLASS as a balancing service

Context

The UK is experiencing a rapid energy transition. System flexibility and 'smart grid' capabilities have been identified as vital enablers for a fast and smooth energy transition. Ofgem has an overarching goal to take advantage of a fully flexible system to bring more renewable generation online, while simultaneously keeping costs down for all consumers.[381]

DNOs can provide network voltage control and network management services via the remote management of deployed network assets. These services are commonly referred to as Customer Load Active System Services (CLASS[382]). Figure 120 illustrates how these services work and how costs and revenues are treated.

376 Noting that currently, the concept of network support services is that they are designed for DNSPs to manage their networks to reliability standards and are not designed to intervene in market operation. However, during contingency events, consideration could be given to whether DNSPs could procure network support services to alleviate network issues during such events.

377 AEMO. N.d., Reliability and Emergency Reserve Trader (RERT). https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert

378 Victorian Government. N.d., Voltage management in Distribution Networks Consultation. https://engage.vic.gov.au/voltage-management-in-distribution-networks-consultation-paper

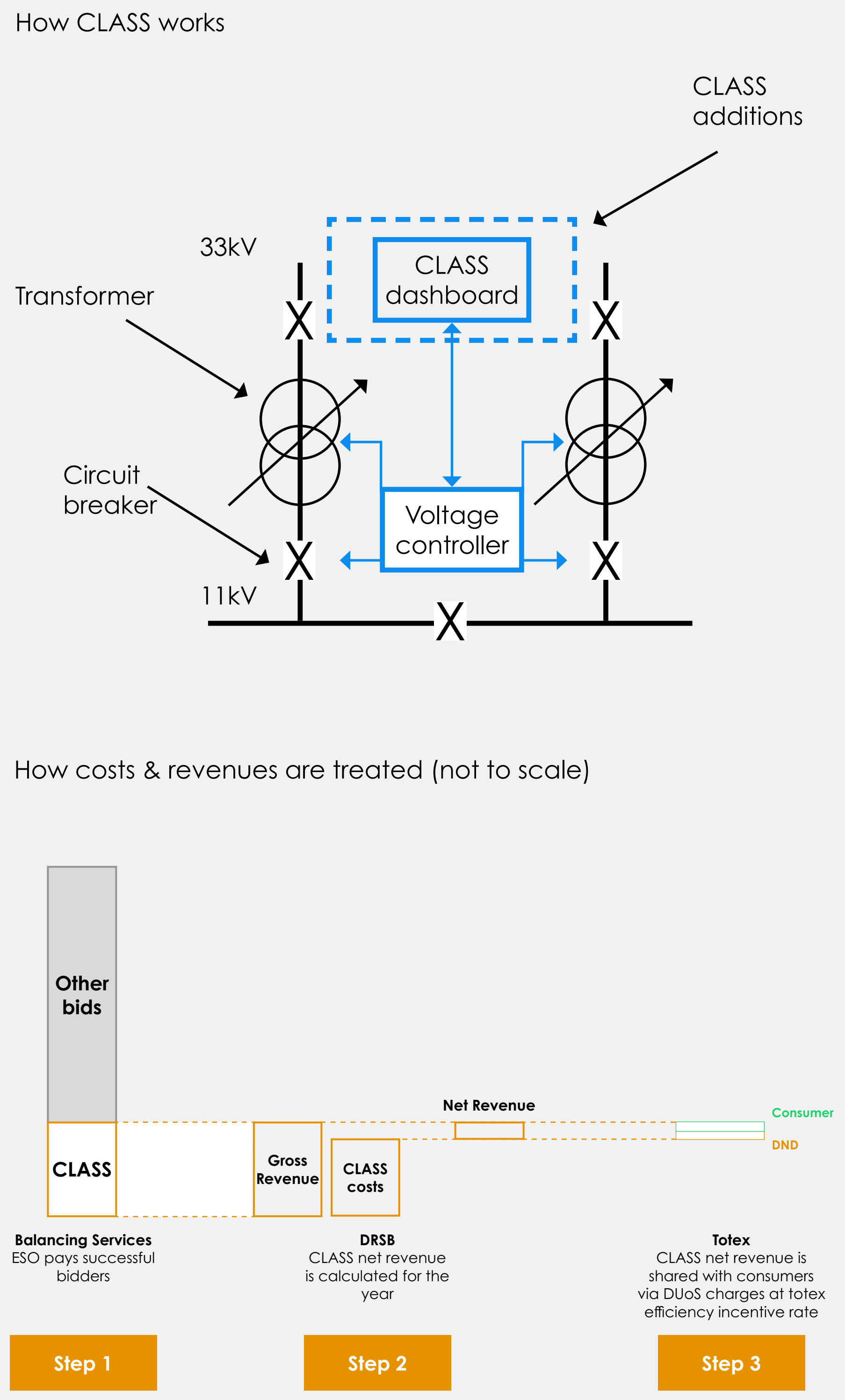
379 Ofgem. 2022, Decision: Regulatory treatment of Customer Load Active System Services as a balancing service in the RII0-ED2 price control. https://www.ofgem.gov.uk/publications/decision-regulatory-treatment-class-balancing-service-riio-ed2-network-price-control

380 National Grid ESO. N.d., Balancing Services. https://www.nationalgrideso.com/industry-information/balancing-services

381 Ofgem. 2022, Decision: Regulatory treatment of Customer Load Active System Services as a balancing service in the RII0-ED2 price control. https://www.ofgem.gov.uk/publications/decision-regulatory-treatment-class-balancing-service-riio-ed2-network-price-control

382 Electricity North West. N.d., What is CLASS? https://www.enwl.co.uk/go-net-zero/innovation/key-projects/class/what-is-class/

Figure 121: How CLASS works and how costs and revenue are treated



Source: Ofgem, Consultation on the Regulatory treatment of CLASS as a balancing service in RIIO-ED2 network price control. https://www.ofgem.gov.uk/publications/regulatory-treatment-class-balancing-service-riio-ed2-network-price-control-2022-consultation

Ofgem Decision to allow CLASS as a balancing service

Ofgem decided in late 2022 to allow CLASS to be sold to the wholesale market framework where attributable costs and revenues are included in the scope of regulated revenue, on the basis that CLASS is a cost effective, reliable technology that has the potential to reduce energy bills for consumers.

This decision creates greater competition in the balancing services market and allows consumers to benefit from sharing in any profits, reflecting that CLASS uses network assets paid for in regulated revenues (see previous Figure 120).

Ofgem will quantitatively review the level of CLASS deployment, and net revenue earned by DNOs, to understand the appropriateness of the regulatory treatment of CLASS as a balancing service over the next five years.

Potential opportunities in the NEM

This Ofgem decision and the UoM research suggest further exploration should be considered in Australia to identify if there could be a cost-effective way for DNSPs to support wholesale market outcomes that deliver a smarter, more affordable grid for consumers.

In the context of a rapid energy transition that requires GWs of flexibility in the power system – and the ISP and ESOO recommendations that demand coordination and flexibility is required urgently – significant amounts of flexibility will be needed.

If a system like CLASS can technically deliver greater system flexibility, support efficient wholesale market outcomes and is relatively inexpensive, then it could be considered as a future 'DSO' use case to inform thinking on roles and responsibilities.

Further work is required to understand how DSO capabilities to provide services to support market outcomes could operate in the Australian context and what the appropriate incentive mechanism is for DNSPs to deploy these DSO capabilities.[383]

9.3.4.1 Existing regulatory incentives to use network support services

The main elements of the current regulatory framework to drive efficient distribution network management include:

- Obligations for DNSPs to undertake market testing of NSS for projects above a monetary threshold (RIT-D).[384]
- Capital Expenditure Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme (EBSS), which ensure DNSPs are not penalised when they underspend capex but overspend on opex as a result of network support solutions:
  - The CESS provides financial reward for DNSPs whose capex becomes more efficient (outperform their capex allowance) and applies financial penalties for those that become less efficient (overspend their capex allowance). As such, it is an incentive for DNSPs to minimise capex during a regulatory control period.[385]
  - The EBSS is an incentive for DNSPs to minimise opex during a regulatory control period. The scheme provides a continuous incentive for DNSPs to achieve efficiency improvements in opex. The EBSS rewards DNSPs that make incremental efficiency gains (by allowing DNSPs to retain underspend) and penalises those that make incremental efficiency losses (by adjusting for any overspend in each year of the regulatory control period).[386]

383 Three Victorian DNSPs – Citipower, Powercor and United Energy – sought potential solutions from third parties to address load capacity limitations on the low voltage network during peak demand periods. The NSS solutions sought could include DER or other demand management solutions and resources.

Citipower, Powercor and United Energy. N.d. https://media.unitedenergy.com.au/forms/Request-for-Information-Non-Network-Solution-Final.pdf

383 This was not used for the voltage management services due to time limitations.

384 NER clause 5.15.2(c) and the AER prescribe that RIT–D proponents must consider all credible options, including non-network options, without bias.

385 AER. 2023, Capital Expenditure Incentive Guideline for Electricity Network Service Providers April 2023. https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Capital%20expenditure%20incentive%20guideline%20-%2028%20April%202023_2.pdf

386 AER. 2013, Better Regulation: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers November 2013. https://www.aer.gov.au/system/files/5.%20AER%20efficiency%20benefit%20sharing%20scheme%20-%20November%202013.pdf

- The Demand Management Incentive Scheme (DMIS) and Demand Management Incentive Allowance (DMIA):
  - The objective of the DMIS is to give DNSPs an incentive to undertake demand management projects that are efficient and contribute – in part or in whole – to resolving a network constraint.[387]
  - In determining whether a project is efficient, the AER requires DNSPs to test the demand management services market. The scheme therefore seeks to encourage projects that deliver the most value to the DNSP's customers. It also promotes the development of NSS trade by requiring DNSPs to seek out third parties to propose demand management solutions. DNSPs are required to form contracts with third parties that propose a solution that delivers the most value to the DNSP's customers.
  - While the DMIS is an incentive to undertake efficient expenditure on relevant NSS relating to demand management, it is complemented by the DMIA, which provides an opportunity for DNSPs to earn additional revenue for research and development in demand management projects with the potential to reduce long-term network costs. It is provided in the form of a fixed allowance for each regulatory control period, with an additional percentage of the distributor's annual revenue requirement.[388] If the allowance is not spent at the end of the regulatory control period, a carryover amount is calculated and recovered from distributors (i.e. it is a 'use it or lose it' allowance).
  - DNSPs are required to justify and seek AER approval of actual DMIA expenditure on NSS projects. If a DNSP does not use all of its allowance in the regulatory control period, it is required to return the amount of any underspend to customers through tariff reductions. Any overspend would be borne by the DNSP.
  - The DMIA therefore provides revenue to DNSPs, giving them an incentive to deliver innovative NSS with the potential to reduce long-term network costs and benefit the DNSP's customers.

Another regulatory consideration that will need to be explored is whether there would be any conflicts with any DSO activities and associated regulation. Under existing ringfencing guidelines, DNSPs are prohibited from providing certain services unless they have been granted a waiver by the AER;[389] for example, providing contestable services such as RERT.

In 2022, the AER granted a temporary waiver under the Electricity Distribution Ring-fencing Guidelines to DNSPs, allowing them to contract with AEMO to provide RERT services via voltage management.[390] In this instance, the wavier was granted on the basis that it was necessary to meet AEMO's need to procure RERT to address forecast reliability gaps, and could provide benefits to all electricity consumers through likely lower RERT costs .

INSIGHTS

Consideration of DNSP services when defining the role of DSOs

When considering and defining the role of DSOs and the extent to which they are allowed to provide market services, policy makers should consider whether DNSP services are contributing to system level flexibility in the whole electricity market, and in turn, lower costs for all consumers.

387 AER. N.d., Final Decision: Demand management incentive scheme and innovation allowance. https://www.aer.gov.au/system/files/D17-173575%20AER%20-%20Fact%20Sheet%20-%20Final%20demand%20management%20incentive%20scheme%20and%20innovation%20allowance%20mechanism%20-%2013%20December%202017.pdf

388 AER. 2017, Explanatory Statement: Demand management innovation allowance mechanism: Electricity distribution network service providers December 2017, p 6. https://www.aer.gov.au/system/files/AER%20-%20Explanatory%20statement%20-%20Demand%20management%20innovation%20allowance%20mechanism%20-%2014%20December%202017.pdf

389 AER. 2021, Ring-fencing guideline (electricity distribution: Version 3 November 2021. https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/ring-fencing-guideline-electricity-distribution

390 AER. 2022, Decision – Distribution ring-fencing class waiver for Reliability and Emergency Reserve Trader (RERT) via voltage management December 2022. https://www.aer.gov.au/networks-pipelines/ring-fencing/ring-fencing-waivers/reliability-and-emergency-reserve-trader-rert-via-voltage-management-ring-fencing-class-waiver-december-2022

A concern raised by stakeholders during the AER's consultation process on the matter was that the revenue earned by DNSPs from providing RERT services would be unregulated revenue.[391] As such, the specific concern was that the DNSPs' customers would be unlikely to benefit from the revenue because it would be unlikely to trigger the threshold in the Shared Asset Guideline that requires DNSPs to share unregulated revenue benefits with their customers.[392]

The Shared Asset Guideline states that DNSPs only need to share unregulated revenues when they exceed 1% of total revenue, and then only 10% of unregulated revenues would be shared with customers.[393] For the 2022-27 regulatory period, AusNet Services' total revenue cap is $2,877m, so the 1% threshold for sharing unregulated revenues with customers would be $28.77m.

By contrast, the deployment of CLASS in the UK requires that distribution networks share unregulated net revenues with customers in greater proportions. The ratio of the revenue that is retained (or paid for if net revenue is negative) by the consumer is determined by the totex efficiency incentive rate, which can vary between distribution networks. For example, if a distribution network has a totex efficiency incentive rate of 55%, then consumers would retain 45% of the profit or pay for 45% of the loss.[394]

The need to share greater proportions of unregulated revenues with customers has been recognised by some DNSPs. The AER summary of verbal feedback to the RERT ring-fencing class waiver consultation[395] identified that:

"Ausgrid and Essential Energy also recognised the need for a mechanism outside of the Shared Asset Guideline to share RERT revenue with consumers. Sharing unregulated revenue earned from the use of regulated electricity supply assets will be important as increasing opportunities emerge for DNSPs to participate in markets for new services."

DNSP capabilities needed to manage distribution network capacity through DOEs, and procure/manage network support services from DER, also align with capabilities that can unlock flexible capacity in the distribution network to support electricity market outcomes.

As the DSO role evolves, clear regulatory mechanisms will be required to provide incentives for unlocking the flexible capacity of the 'smart grid' of distribution networks to benefit all consumers.

391 AER. 2022, Decision – Distribution ring-fencing class waiver for Reliability and Emergency Reserve Trader (RERT) via voltage management December 2022. https://www.aer.gov.au/networks-pipelines/ring-fencing/ring-fencing-waivers/reliability-and-emergency-reserve-trader-rert-via-voltage-management-ring-fencing-class-waiver-december-2022

392 AER. 2013, Better Regulation: Shared Asset Guideline November 2013, p 8. https://www.aer.gov.au/system/files/AER%20shared%20asset%20guideline%20-%20Shared%20asset%20guideline%20-%20November%202013.pdf

393 AER. N.d., Better Regulation Shared Asset Guideline. https://www.aer.gov.au/system/files/AER%20Better%20Regulation%20factsheet%20-%20shared%20asset%20guideline%20-%20November%202013.pdf

394 Ofgem. 2022, Decision: Regulatory treatment of Customer Load Active System Services as a balancing service in the RII0-ED2 price control. https://www.ofgem.gov.uk/publications/decision-regulatory-treatment-class-balancing-service-riio-ed2-network-price-control

395 AER. 2022, Decision – Distribution ring-fencing class waiver for Reliability and Emergency Reserve Trader (RERT) via voltage management December 2022. https://www.aer.gov.au/networks-pipelines/ring-fencing/ring-fencing-waivers/reliability-and-emergency-reserve-trader-rert-via-voltage-management-ring-fencing-class-waiver-december-2022. This was identified in a Grids.dev article, Can we talk about DSO regulation in the NEM?. Grids.

2023, Can we talk about DSO regulation in the NEM? https://grids.dev/posts/can-we-talk-about-dso-regulation/

INSIGHTS

Considerations when defining the DSO roles and responsibilities

Policy makers should consider further investigating how DNSPs' role could evolve to support economically efficient DER integration.

Through the definition of the role, there should also be further exploration of the role o DNSPs in moving beyond efficiently managing the physical network infrastructure to also facilitating broader efficiency outcomes, including how flexible capacity in network infrastructure (e.g. different applications of dynamic voltage management) can deliver savings for all consumers.

Once the DSO role and responsibilities are defined, a review of regulatory incentives could be considered to evaluate whether current incentives are appropriate, and simple to navigate, to support implementation of defined DSO capabilities. In undertaking the review, consideration should be given to the growing need for flexibility across the power system to enable Australia's energy transition.

9.4 Key insights and implications for industry

The Project EDGE research provided the following key insights and implications for industry.

Policy makers

- Continue the effort to adopt a national approach to the DOE rollout, as first raised in the DEIP DOE Outcomes report.[396]
- Consider requesting the AER to lead collaboration with industry and market bodies to develop an appropriate definition of the Australian DSO role and the capabilities required, and the trigger points for when they are needed.
- After the DSO role is defined, support industry collaboration to identify and technically define necessary DSO capabilities and the progressive uplift in DNSP capability required over time.
- After the DSO role is defined, review regulatory mechanisms to ensure appropriate incentives for DNSPs to implement DSO capabilities that can deliver benefits to all consumers.

For DNSPs

- Develop appropriate capabilities to support the implementation of DOEs and facilitate DER participation in energy markets and service provision. In doing so, DNSPs should consider:
  - Developing their own roadmaps appropriate to their network needs
  - Adopting a targeted approach to investment based on DER penetration in their networks and aligned with the AER's regulatory economic framework.
- Develop further DSO capabilities to procure network support services from DER.
- Proactively participate in industry collaboration with the AER and market bodies to identify a consistent definition of the DSO capabilities required and the trigger points for when they are needed.

396 DIEP. 2022. DEIP Dynamic Operating Envelopes Workstream: Outcomes Report. https://arena.gov.au/knowledge-bank/deip-dynamic-operating-envelopes-workstream-outcomes-report/

EDGE AEMO mondo AusNet

Yackandandah, a picturesque locality three hours North East of Melbourne, Victoria – where the community has long pioneered sustainable energy solutions and actively participated in the Project EDGE trial.