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Project EDGE
Cost Benefit Analysis – Final Report
Executive Summary

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Deloitte
Access Economics

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Acknowledgements

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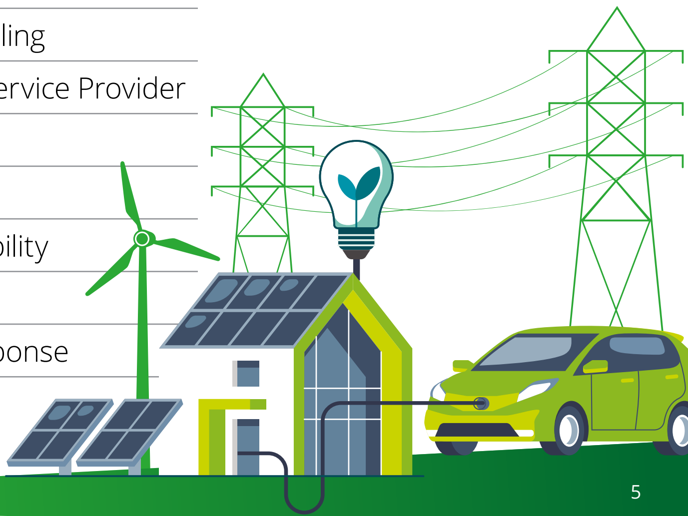
Glossary

Acronym	Full name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
ARENA	Australian Renewable Energy Agency
BTM	Behind The Meter
B2B	Business-to-business
Capex	Capital Expenditure
CBA	Cost Benefit Analysis
CECV	Customer Export Curtailment Value
CER	Consumer Energy Resource(s)
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
DER	Distributed Energy Resource(s)
DERMS	Distributed Energy Resources Management System
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
DSO	Distribution System Operator
DUID	Dispatchable Unit Identifier
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FiT	Feed-in tariff
FTA	Flexible Trading Arrangement
Hp	Hypotheses
IESS	Integrating Energy Storage Systems
ISP	Integrated System Plan
kVA	Kilovolt-amps

kW	Kilowatt
kWh	Kilowatt Hour
LRMC	Long Run Marginal Cost
LSE	Local Services Exchange
LV	Low Voltage
MCA	Multi-criteria Analysis
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
O&M	Operating and Maintenance
OE	Operating Envelope
OEM	Original Equipment Manufacturer
Opex	Operating Expenditure
PV	Photovoltaic
RERT	Reliability and Emergency Reserve Trader
RQ	Research Question
SCED	Security Constrained Economic Dispatch
SRMC	Short Run Marginal Cost
SME	Subject Matter Experts
TEM	Techno-Economic Modelling
TNSP	Transmission Network Service Provider
UoM	University of Melbourne
V2G	Vehicle-to-grid
VCR	Value of Customer Reliability
VPP	Virtual Power Plant
WDR	Wholesale Demand Response



Introduction

It is exciting to imagine a future where most of our energy needs are met by renewable and low-cost sources of energy.

A coordinated approach to the integration of an expanding volume of distributed energy resources (DER)[1] into the electricity market can support this future through mitigating existing barriers to DER uptake and lowering costs for all consumers.

Apart from those in Western Australia and the Northern Territory, the vast majority of Australians access electricity via the National Electricity Market (NEM). Over coming decades, the share of electricity generation derived from household and business rooftop solar is expected to increase significantly.

The increasing reliance on electricity generated from rooftop solar is forecast to occur over a period when consumers are also expected to increasingly move away from petrol, diesel, and natural gas for everyday use. This is, in turn, expected to significantly increase annual electricity demand, highlighting the urgency of making sound, evidence-based decisions about the future of DER in the NEM.

Without action, we instead risk making operation of the electricity market more difficult and more expensive for all consumers. In simple terms, this means that reliability of electricity supply and the costs to access that supply will be adversely impacted unless we urgently agree on a better way to transition to a net zero emissions future.

This document presents key findings from the Project EDGE CBA demonstrating that a coordinated market-based approach to DER integration in the NEM will be crucial to success.

Project EDGE purpose and approach

Project EDGE was established to further understand the outcomes for all consumers of greater DER participation in the NEM.

This multi-year project was conceived as a field trial building on prior industry initiatives. It was designed to demonstrate an end-to-end market arrangement that maximises the value of consumer DER and supports a NEM that could deliver reliable, affordable, and sustainable supply of electricity for all consumers.

The Project EDGE CBA

As part of Project EDGE, Deloitte Access Economics (Deloitte) and Energeia conducted an independent cost benefit analysis (CBA)[2] - this report - to provide insights and direction to energy market participants and policy makers of the economic value for all consumers from the Project EDGE arrangement for DER participation in the NEM.

The CBA utilises where practical the most recent forecasts. Exploring a range of scenarios under which DER participation within the NEM would deliver the long-term interests of electricity consumers[3] across a 20-year time horizon (FY23-FY42).

The purpose of this CBA is to provide policy makers and industry leaders with an assessment of the costs and benefits associated with NEM-wide implementation of the demonstrated DER integration model using evidence from Project EDGE. The CBA is intended to inform policy decisions and industry choices that provide optimal outcomes for consumers in the transition to net zero emissions and a higher DER electricity market.

1 The term Consumer Energy Resources (CER) has emerged to refer to consumer-owned DER and is used interchangeably with DER by some stakeholders. This report uses the term DER to cover all assets connected to the distribution network, both consumer and non-consumer owned or leased.
2 The applicability of CBA findings is to an understanding of the NEM as of March 2023, and through the voluntary contributions of the Project EDGE participants (AEMO, AusNet and Mondo), DER Aggregators participating in Project EDGE, non-participating DER Aggregators and technology vendors.
3 The CBA is not intended to act as a business or investment case for individual market participants.

The CBA is ultimately an economic assessment. Prepared in consultation with industry stakeholders, the guiding principle 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.

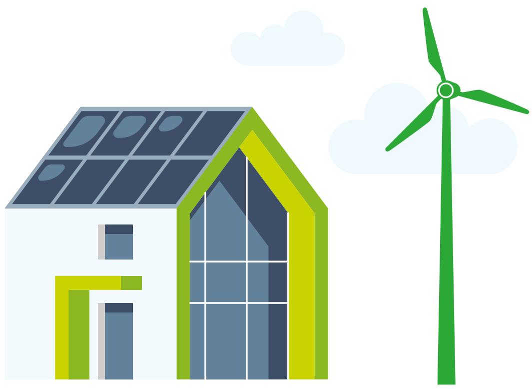
While the outcomes of the CBA represent our best estimates at this time, this assessment is projected to serve as a credible, evidence-based guide for those tasked with crafting the next phase of work for the energy transition.

CBA Approach

The CBA 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 utilised 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 assumptions[4] (AEMO ISP Step Change), reflected in Scenarios 1-5.
2) A set of high DER load and uptake assumptions[5] (High DER), reflected in Scenarios 6-10.

Two scenarios are classified as base cases in the CBA (Scenarios 1 and 6)[6]. 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 flexible exports, and satisfactory DER customer products to enable active DER to be separately managed from passive load
- No implementation of Scheduled Lite[7] type participation arrangements, limiting Market Operator and DNSP visibility of DER (however all other scenarios assume Scheduled Lite to account for the incremental impact).

Subsequent scenarios reflect a gradual increase in complexity against the base cases of the selected capabilities of DER participation. Figure 1 below outlines the key arrangements of each scenario[8].

4 AEMO, 2022 ISP (June 2022), at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en
5 Energeia (2020). Renew DER Optimisation (Stage II): Final report (for Renew), page 4 and page 32, at https://energeia.au/wp-content/uploads/2022/03/Renew-DER-Optimisation-Final-Report-210930v2_compressed.pdf
6 Given that two separate forecast load and DER uptake assumptions are utilised, 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.
7 AEMO, at https://aemo.com.au/en/initiatives/trials-and-initiatives/scheduled-lite
8 Detailed information on the Project EDGE CBA 'as-built' methodology is published at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

The CBA scenarios are designed to 'bookend' gradual progression of maturity enabling interpolation of decision making along the DER implementation pathway.

Figure 1. CBA scenarios [9] [10] [11] [12]

		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 / Local Services Exchange (LSE)	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

		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 / Local Services Exchange (LSE)	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

Legend: Maturity of DOE and market configurations

9 The load and DER uptake assumptions for Scenarios 1-5 are based on AEMO, 2022 ISP (June 2022), at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en. The load and DER uptake assumptions for Scenarios 6-10 are based on Energeia (2020), Renew DER Optimisation (Stage II): Final report (for Renew), page 4 and page 32, at https://energeia.au/wp-content/uploads/2022/03/Renew-DER-Optimisation-Final-Report-210930v2_compressed.pdf

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

11 All scenarios assume 41% VPP participation as a % of storage by 2030 (8.9GWh for Scenarios 1-5 and 16.2GWh for Scenarios 6-10) and 52% VPP participation as a % of storage by 2042 (34.2GWh for Scenarios 1-5 and 58.2GWh for Scenarios 6-10).

12 Under Scenarios 1-5 36,178 MWs of Solar PV and 21,785MWhs of Battery Storage is assumed in 2030 and 57,374 MWs of Solar PV and 64,111 MWhs of Battery Storage is assumed in 2042. Under Scenarios 6-10 47,428 MWs of Solar PV and 39,334MWhs of Battery Storage is assumed in 2030 and 103,860 MWs of Solar PV and 108,959 MWhs of Battery Storage is assumed in 2042.

Figure 2 below outlines the DOE and market configurations considered in the CBA

Figure 2. Arrangements within the CBA scenarios

Dynamic Operating Envelope Configurations

Constraint Optimisation Frequency

The frequency **(Annual, Daily or Intra-day)** of updating the constraint optimisation settings that govern the safe operating distribution network limits.

DOE Optimisation Methodology

Approximation option involves analytical approximation of the network capacity using mainly historical network and Advanced Metering Infrastructure (AMI) data.

LV impedance model option involves a load flow calculation using low voltage network impedance models, customer data and operational forecasts.

DOE Customer Coverage

VPP only means only DER that is participating in a VPP would be receiving DOEs.

100% means all new DER connected to the distribution network is active and would be receiving DOEs.

Objective Function for Network Capacity Allocation

Nameplate involves allocating DER capacity in a way where the optimal outcome is a pro-rata split of distribution network capacity based on the nameplate rating of the DER.

Maxmise Service involves allocating DER capacity, with the aim to maximise the volume of export or import from them. In this approach, higher DOE will be allocated to DER facing lesser network constraints.

Market Configurations

Scalable Data Exchange

- Point-to-point
- Data Hub

Local Services Exchange (LSE)

LSE is the interface to facilitate visible, scalable and competitive trade of DER-based network support services for local network constraint management. The data exchange for the LSE can be via point-to-point or a data hub.

Central Finding

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

Consistent with the Energy Security Board (ESB) CER Implementation Plan[13], 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, including:

- **Overly conservative and 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 DER data exchange which limits the scalability of DER
- **Limited visibility** of active DER minimises situational awareness and forward-looking operational and network planning for the Market Operator and DNSPs
- **Social license** challenges, for example obtaining 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[14] as we move towards a higher DER future.

Project EDGE tested market arrangements to overcome these barriers.

> The findings show quantitatively that greater coordination of active DER in the NEM via the Project EDGE arrangement can result in an incremental benefit to all consumers up to $5.15b[15] under the AEMO ISP Step Change DER uptake assumptions and up to $6.04b[16] 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. It was found to 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.[17]

13 ESB, CER Implementation Plan (July 2021), at https://esb-post2025-market-design.aemc.gov.au/integration-of-distributed-energy-resources-der-and-flexible-demand
14 AEMO (August 2022), at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo
15 Scenario 5 - Advanced DOE, High Coverage with Data Hub (AEMO ISP Step Change).
16 Scenario 10 - Advanced DOE, High Coverage with Data Hub (High DER).
17 The CBA analysed curtailment of customer DER exports due to distribution network constraints by simulating the impacts of the DOE configurations (this represented the majority of analysed curtailment). In addition, wholesale market curtailment was assumed to occur when additional DER generation export would push operational demand beyond the minimum operational requirement of the NEM power system, thereby resulting in the need to curtail generation from DER, which would be done through a VPP or DOE arrangement b) For broader assessment of variable renewable energy curtailment see page 47 in the 2022 AEMO ISP.

Based on the capabilities tested within the CBA scenarios, the benefits are 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
- **LSE** providing a scalable and standardised market configuration for DNSPs to procure network support services from DER Aggregators, who co-optimise network support services and wholesale services within their DER portfolio
- **Visibility of DER** for the Market Operator and DNSPs to improve their awareness of where DER are installed on the network and how they behave to enhance situational awareness, operational forecasting, and network planning functions. Ultimately, reducing costs via enabling more accurate (and less conservative) operations across the network.

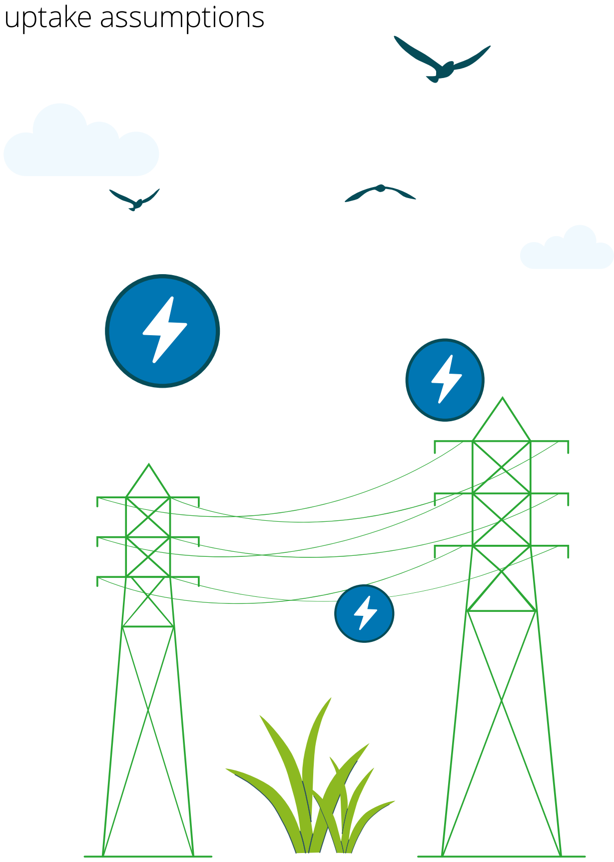
Active DER participation in VPPs is critical to realise the benefits associated with the capabilities assessed within the CBA scenarios. This will enable DER to make a coordinated response to market prices and system security events at scale. Figure 3 illustrates the increasing benefits to market participants as configurations evolve.

The CBA modelled the emissions (tCO2e)[18] associated with electricity generation per CBA scenario.

This is enabled primarily by greater DOE customer coverage that allows for more network capacity to be unlocked and utilised by DER and VPPs.

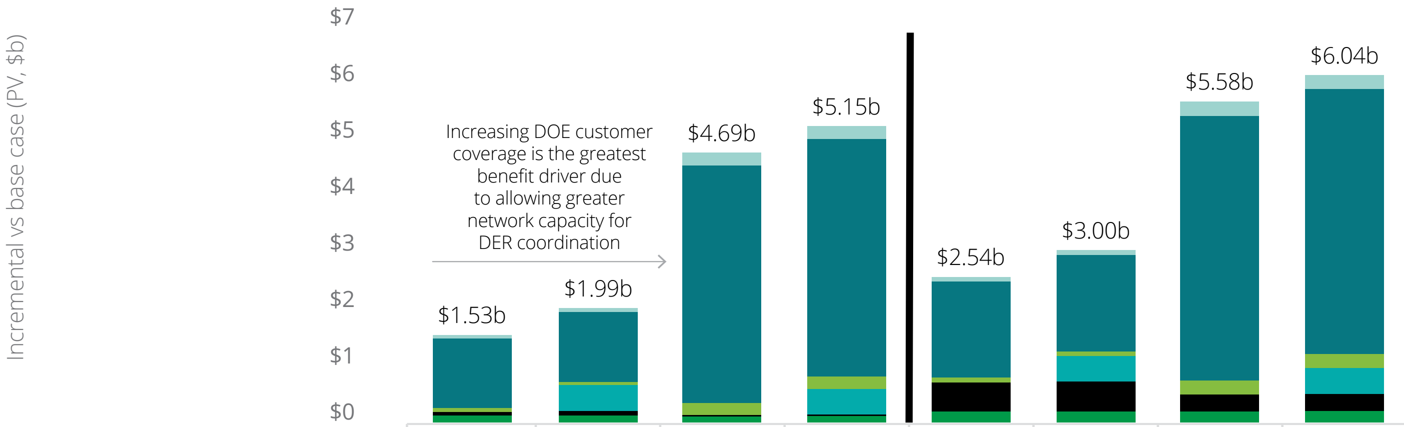
A social cost of carbon[19] was applied to value the avoided emissions (tCO2e).[20] In FY23 (CBA base year) the assumed social cost of carbon is ~$101 (per tCO2e) and in FY42 the assumed social cost of carbon is ~$147 (per tCO2e).

The CBA found that across the 20-year time horizon total emissions avoided can be up to 18,859,157 tCO2e ($1.54b)[21] under the AEMO ISP Step Change DER uptake assumptions and up to 32,871,522 tCO2e ($2.60b)[22] under the High DER uptake assumptions



18 CO2e is a measure used to compare the emissions from various greenhouse gases based on their global-warming potential, by converting amounts of other gases to the equivalent amount of carbon dioxide with the same global warming potential.
19 A social cost of carbon when performing a CBA to encompass a societal welfare point of view.
20 Environmental Protection Agency (2017), The Social Cost of Carbon.
21 Scenario 5 - Advanced DOE, High Coverage with Data Hub (AEMO ISP Step Change).
22 Scenario 10 - Advanced DOE, High Coverage with Data Hub (High DER).

Figure 3. CBA findings – key drivers of value incremental to the base cases (20-year time horizon, $FY23, 4.83% discount rate)[23]



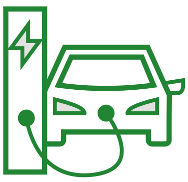
Key drivers of value across the CBA Scenarios	Scenario 2 (Simple DOE, Moderate Coverage)	Scenario 3 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 4 (Advanced DOE, High Coverage)	Scenario 5 (Advanced DOE, High Coverage with Data Hub)	Scenario 7 (Simple DOE, Moderate Coverage)	Scenario 8 (Simple 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) [24]	$0.12	$0.12	$0.12	$0.12	$0.20	$0.20	$0.20	$0.20

Notes: Total power system 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. Total indicative implementation costs for the Project EDGE arrangement for the Market Operator, DNSPs and DER Aggregators is $0.92b under Scenario 3, $1.35b under Scenario 5, $2.09b under Scenario 8 and $3.94b under Scenario 10.

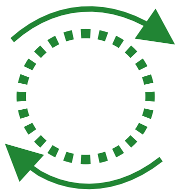
23 Scenarios 2-5 are compared to Scenario 1, while Scenarios 7-10 are compared to Scenario 6.
24 Assuming Flex bidding mode.

Additional emerging customer benefits

The CBA provides a 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:



Vehicle to Grid (V2G) coordination – given the increasing uptake of electric vehicles (EVs) in Australia[25], 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 into 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.

Additional DER services – effective market configurations have the potential to facilitate further value from DER as industry maturity and needs evolve by enabling new DER-based service innovations to be more easily adopted. For example, a data hub could support additional transactions as the industry evolves and innovates such as Retailers requesting DER Aggregators to manage DER exports and hedge their exposure during periods of negative prices.

Relevance of findings by market participant type

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

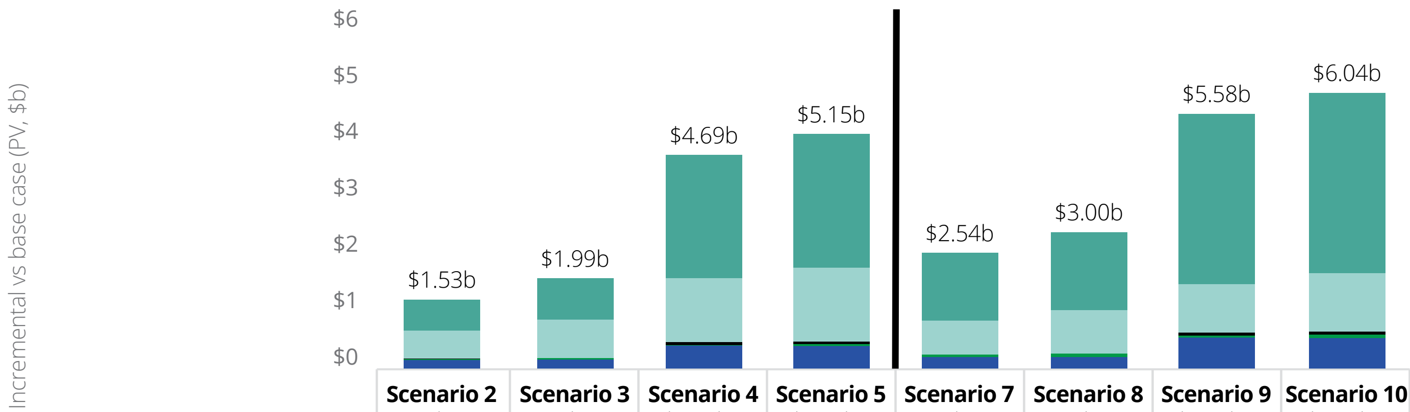
- Increased revenue opportunities for DER Aggregators[26] and, as a consequence, DER Customers, due to:
  - a reduction in DER export curtailment,
  - partial displacement of large generators enabled via wholesale integration of active DER[27],
  - the provision of contingency Frequency Control Ancillary 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 data exchange costs

25 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, State of Electric Vehicles (July 2023), at https://electricvehiclecouncil.com.au/wp-content/uploads/2023/07/State-of-EVs_July-2023_.pdf
26 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.
27 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.

- Lower TNSP costs in maintaining and increasing the capacity of the transmission network
- Lower Market Operator costs through reduced data exchange costs and enhanced management of power system security issues due to greater visibility of active DER.

Figure 4 below 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.

Figure 4. CBA findings across market participants (20-year time horizon, $FY23, 4.83% Discount rate)[28 29]



	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 power system 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.

28 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.
29 'Other' relates to broader 'whole of system' impacts as compared to a specific market participant.

Insights on Roles and Market Configurations

1.

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

A data hub model would provide 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 one industry data hub.

The CBA found that across the 20-year time horizon[30], a centralised data hub would reduce costs by up to $0.44b and a decentralised data hub would reduce costs by up to $0.45b compared to a point-to point approach.

In addition, a data hub as compared to a point-to point approach could 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.

30 This CBA assumes for the purposes of assessing the scalable DER data exchange approaches that there will be 13 DNSPs by FY42 each integrating with on average 27 DER Aggregators/Retailers/ Original Equipment Manufacturer (OEM) and assumes that there will be 52 DER Aggregators/Retailers/OEMs by FY42 (29 in FY23 and 45 in FY30) each integrating with on average 6 DNSPs. The number of DER Aggregators/ Retailers/OEMs has been informed by the current number of market participants in the NEM currently offering VPPs, the NEM Registration and Exemption List and the VPP uptake assumptions used in this CBA. It is assumed that not all DER Aggregators/Retailers/OEMs using the DER data exchange will participate on the spot market (e.g., some will only be using the DER data exchange for the purposes of FCAS and business-to-business (B2B) services).

2.

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

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.

In Project EDGE, DER Aggregators utilised 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 each participant would 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 University of Melbourne (UoM), who noted that the value of network support services is directly linked to its ability to relive network constraints, which are locational and temporal[31]. The CBA has adopted a conservative approach to valuing the benefits of an LSE, based only on its use to reduce DER export curtailment. Due to insufficient data the potential benefits related to the use of an LSE to maintain reliability and quality of electricity supply in the distribution system was not quantified.

To simplify the process of assigning a value to the use of an LSE to reduce DER export curtailment[32] the CBA has derived an average price associated with reduced curtailment[33], using the 2022 customer export curtailment values (CECV) published by the AER[34]. This price has been applied to the forecast annual volume of curtailed exports[35].

The CBA found that across the 20-year time horizon[36] the implementation of an LSE (with data exchange via a data hub) can result in an incremental benefit of up to $0.08b[37] under the AEMO ISP Step Change assumptions and up to $0.51b[38] under the High DER uptake assumptions based only on the use of an LSE to reduce DER export curtailment.

31 S. Riaz, J. Naughton, University of Melbourne, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches (March 2023).
32 UoM analysis suggests that reactive power services from DER can be applied to relieve export constraints in the low voltage network as exports are typically limited by voltage limits rather than the thermal ratings of network assets. Refer to S. Riaz, J. Naughton, University of Melbourne, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches (March 2023).
33 The calculation is based on using a CECV average value across the NEM over the 20-year CBA time horizon of $48.38/MWh.
34 AER, 2022. Final CECV Methodology, at https://www.aer.gov.au/system/files/Final%20customer%20export%20curtailment%20value%20methodology%20-%20June%202022.pdf
35 Based on the Energeia Techno-economic modelling (TEM) outputs for potential avoided voltage constraint curtailment (post DOE configurations tested within this CBA scenarios) over the 20-year CBA time horizon.
36 This CBA assumes for the purposes of assessing the LSE that there will be 13 DNSPs by FY42 each integrating with on average 7 DER Aggregators/Retailers/OEMs and assumes that there will be 13 DER Aggregators/Retailers/OEMs by FY42 (0 in FY23 and 12 in FY30) each integrating with on average 3 DNSPs.
37 Scenario 3 - Simple DOE, Moderate Coverage with Data Hub (AEMO ISP Step Change).
38 Scenario 8 - Simple DOE, Moderate Coverage with Data Hub (High DER).

3.

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

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

From 2018 to 2020, AEMO and Energy Networks Australia (ENA) undertook OpEN[39] 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, as arrangements of roles in a market drive value, the Project EDGE roles and responsibilities along with some alternatives within the Hybrid Model Framework were assessed in this CBA.

The key feature of the Project EDGE arrangement of roles and responsibilities involves DER Aggregators, on behalf of DER customers, receiving the necessary external signals (such as prices and constraints) and co-optimising DER portfolios across wholesale and business-to-business (B2B) opportunities (e.g., network support services). This 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, is aligned with the National Electricity Objective (NEO) and promotes efficiency by extending current roles and responsibilities rather than creating new or duplicating existing ones.

39 AEMO and Energy Networks Australia (2019), at http://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

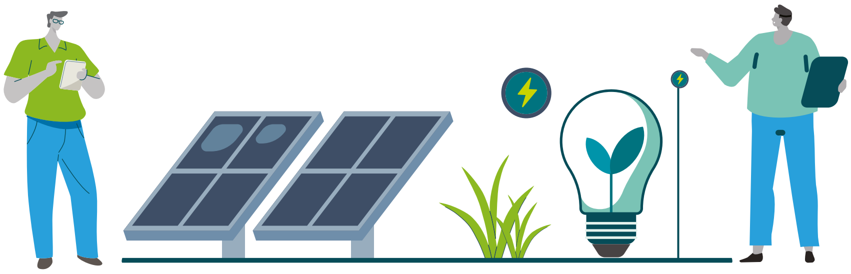
The challenge for industry and policy makers

Acknowledging cross industry reform efforts to date, unlocking value from DER coordination via VPP participation requires coordinated action. The CBA identified immediate foundational priorities to progress towards this outcome:

- **Increasing customer coverage of DOEs** as this enables greater DER export capacity
- **Increasing visibility of DER for the Market Operator and DNSPs**, to enable situational awareness of DER in the NEM
- **Implementation of a scalable data hub to reduce data exchange costs** (a barrier 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' behalf

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 maximise 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 LSE. For example, LSE services are only viable where DER Aggregators can represent and offer sufficient DER capacity at concentrated locations where that support is required, as network constraints are by their nature locational and temporal[40]. As an initial step, DNSPs should consider targeting implementation of LSE for parts of the network with known constraints.



40 S. Riaz, J. Naughton, University of Melbourne, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches (March 2023).

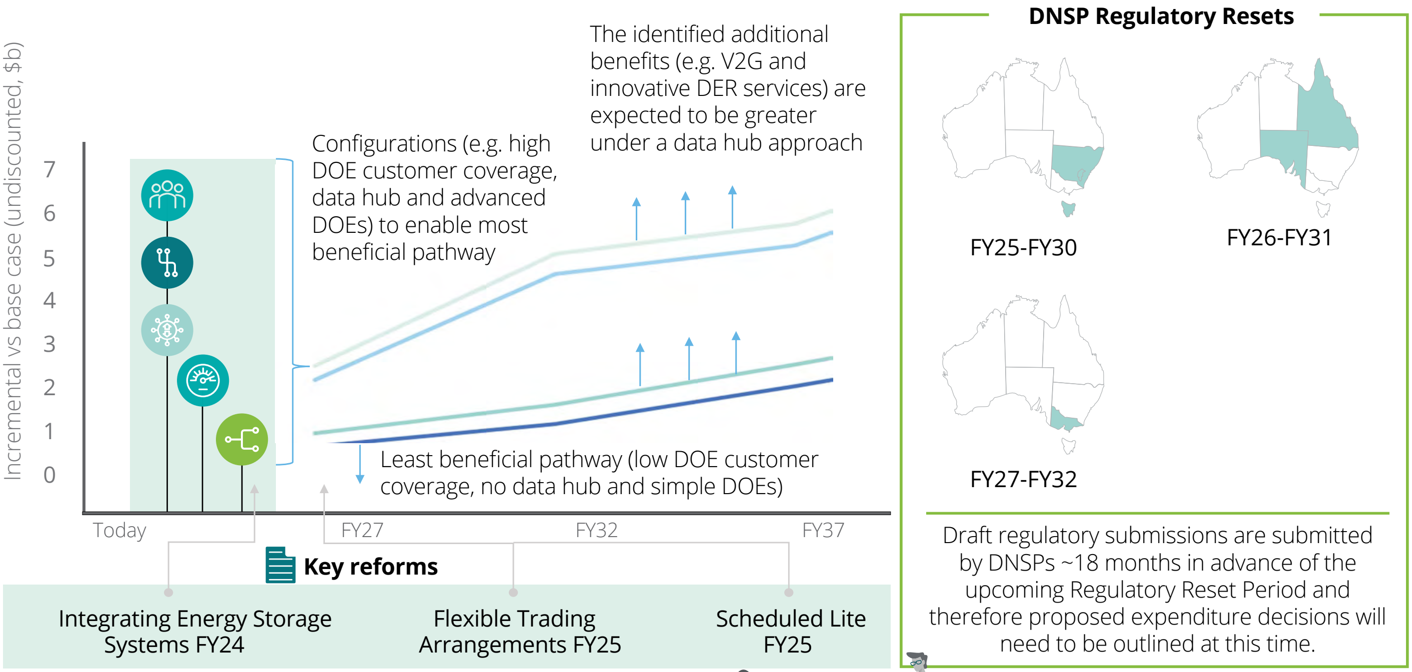
A Roadmap for Implementation – the DER Optimal Investment Pathway

A key purpose of this CBA is to enable key stakeholders in the market to identify a pathway to enact the changes necessary to progress the transition to a higher DER future.

Figure 5 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 reform activities and estimated lead times for the implementation of the capabilities tested within the CBA, to help inform planning.

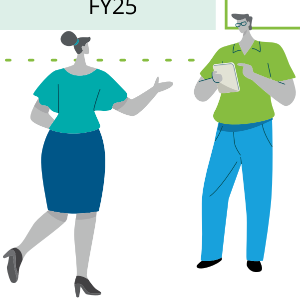
Ultimately, it highlights a DER investment pathway that hinges on focused and coordinated action from policy makers and market participants.

Figure 5. DER implementation pathway



The time for action is now

CBA Functions	Lead Times
DOE Customer Coverage	1-3 years
Visibility of DER	1-5 years
Scalable data hub	1-2 years
DOE Optimisation Methodology and Constraint Frequency[1]	2-5 years
Local Services Exchange	Staged according to network constraints



- **Scenario 2**[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)

1 -LV impedance model optimisation methodology and a maxmise service DOE objective function

2 -Scenarios 6-10 using High DER load and DER uptake assumptions follow the same trend whereby the base case (Scenario 6) has the lowest cumulative benefit from the initial year.

Insights across capabilities tested in the CBA

Based on the selected capabilities tested in the CBA scenarios, the following insights have been identified to support market participants progress the transition to a higher DER future.

Table 1. Key insights across capabilities tested in the CBA

Capabilities within the CBA	Insight	Implication	Timing
DOEs – customer coverage	DOE customer coverage is the key driver for delivering benefits by unlocking network capacity so that more DER can be coordinated via VPPs.	**The enablement of flexible export limits** must be prioritised to support DOE customer coverage; dynamic connection agreements can do this if consumers are incentivised clearly. To promote DOE customer coverage, further work is required to inform consumers of the benefits of DER integration and **to build social licence** with consumers. Importantly, issues around fairness, transparency of value to consumers and trust need to be sufficiently addressed.	1-3 years

Insights across capabilities tested in the CBA

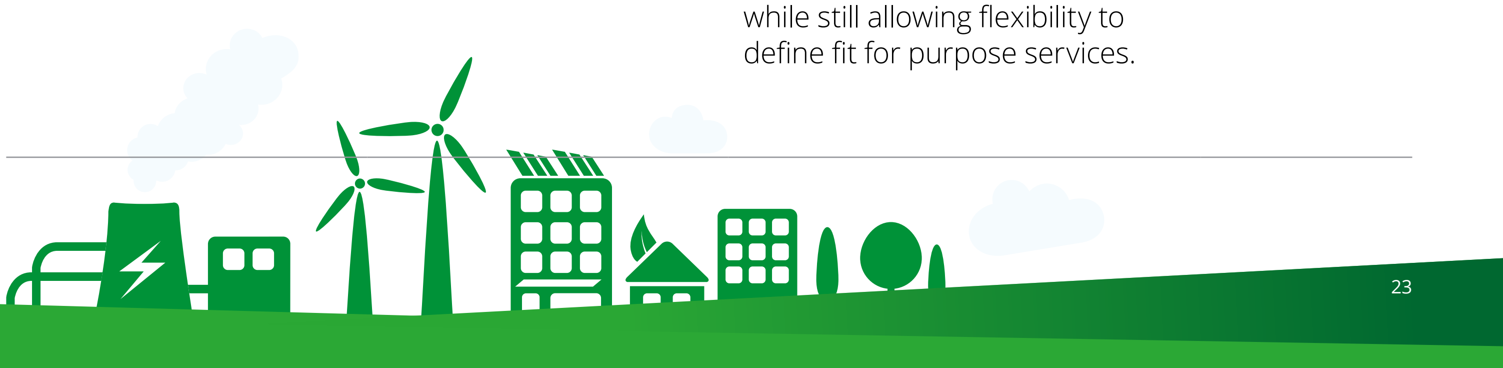
Table 1 continued. Key insights across capabilities tested in the CBA

Visibility of DER	The Market Operator and DNSPs having sufficient visibility of DER is critical to ongoing secure and reliable electricity supply.	The Market Operator should be focused on **building capabilities to know how and in what volumes DER generation/ load 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**[41] rule change. DNSPs should be focused 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.	1-5 years

41 AEMO, at https://aemo.com.au/en/initiatives/trials-and-initiatives/scheduled-lite

Table 1 continued. Key insights across capabilities tested in the CBA

Scalable Data Hub	A data hub approach to scalable DER data exchange will reduce costs and allow new DER-based service innovations to be more easily adopted compared to a point-to-point approach.	**Implementation of a scalable data hub** that provides standardised data services such as DER registration, identity verification and reporting should be prioritised to reduce DER data exchange costs for market participants (e.g., in accessing DOEs or gaining visibility of DER) and facilitate improved access to additional DER services (including B2B services) that can support greater coordination of DER, which drives value to all consumers.	1-2 years
DOEs – optimisation methodology and constraint optimisation frequency	There is merit in gradually introducing more advanced DOE configurations (e.g., LV impedance model optimisation methodology and a maxmise service DOE objective function).	**DNSPs will need to target implementation of DOEs that are optimised** for a given network segment and DER penetration level.	Next 5 years
LSE	The value of a local service is realised in the presence of network constraints which are locational and temporal.	A **targeted approach should be taken to implementing an LSE** based on network needs. Barriers to its adoption 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.	Staged according to network constraints



Conclusion

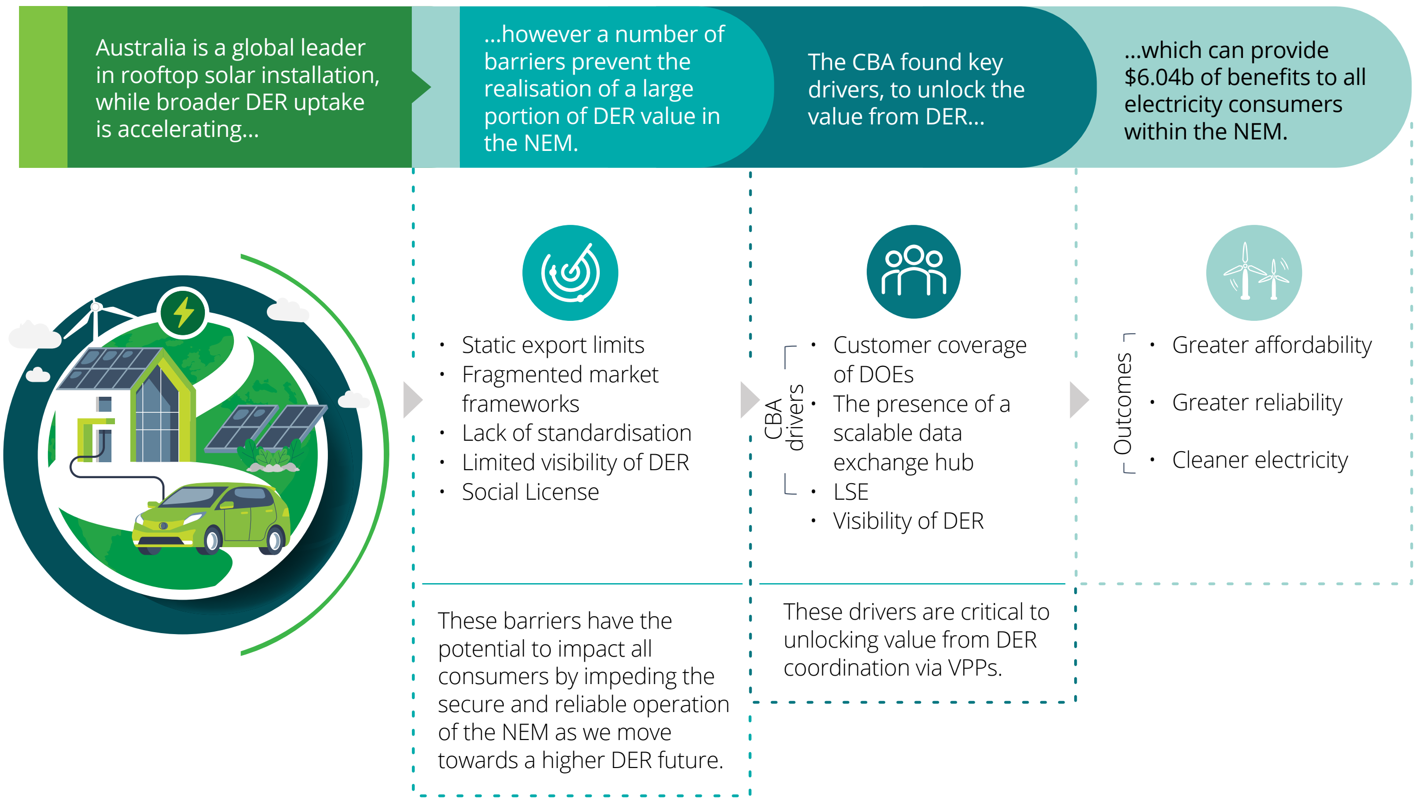
Building on the immediate foundational priorities identified above, this CBA found that a coordinated market-based approach to DER integration within the NEM whereby DER Aggregators and Retailers represent DER Customer needs is economically feasible and can deliver value to all electricity consumers.

There is an immediate opportunity to unlock the benefits of DER by:

- **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.

Figure 6. CBA Summary

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