Explanatory statement

Draft DER integration expenditure guidance note

July 2021

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Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (**AER**) regarding this paper by the close of business, 31 August 2021.

Submissions should be sent electronically to AERinquiry@aer.gov.au.

Alternatively, submissions can be mailed to:

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The AER prefers that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested.

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- clearly identify the information that is the subject of the confidentiality claim; and
- provide a non-confidential version of the submission in a form suitable for publication.

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Enquiries about this paper, or about lodging submissions, should be directed to the Network Expenditure branch of the AER on 1300 585 165 or AERinquiry@aer.gov.au.

Contents

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CECV	Customer Export Curtailment Value
COAG	Council of Australian Governments
CPU	CitiPower, Powercor and United Energy
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
EFA	Expenditure Forecast Assessment
ENA	Energy Networks Australia
FCAS	Frequency Control Ancillary Services
FiT	Feed-in tariff
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test - Distribution
SAPN	SA Power Networks
VaDER	Value of Distributed Energy Resources
VPP	Virtual Power Plant

1 Introduction

This explanatory statement provides our rationale for the Draft DER integration expenditure guidance note. The publication of the draft guidance note follows the publication of a consultation paper, consideration of stakeholder submissions and the publication of the Value of DER methodology study undertaken by the CSIRO and CutlerMerz.[1]

We previously sought views from stakeholders to develop guidance that can be provided to distribution network service providers (DNSPs). The consultation paper Assessing Distributed Energy Resources (DER) Integration Expenditure was released on 19 November 2019 and considers how we may assess DNSPs' proposed expenditure to manage the increasing challenge of accommodating DER on their networks. In particular, the paper considered:

- the current and predicted effects DER is having on networks
- our current approach to assessing DER integration expenditure
- whether our current set of expenditure assessment tools are fit-for-purpose both now and into the future.

We invited written submissions to the consultation paper between 19 November 2019 and 20 January 2020. In response to these submissions, we (and ARENA) commissioned the CSIRO and CutlerMerz to conduct a study into potential methodologies for determining the valuing of DER (VaDER).

We received the final VaDER report from the CSIRO and CutlerMerz in early November 2020. We published the final report, an accompanying FAQ document and stakeholder submissions later that month. The recommendations of the final VaDER report are detailed in Appendix A. In this explanatory note, we respond to these recommendations and provide our preliminary views on each issue and how they are addressed in the VaDER methodology in our draft guidance note.

1.1 What is DER?

Distributed energy resources (DER) include rooftop solar, batteries, electric vehicles and energy management systems. These resources are often located on the consumer's side of the electricity meter, rather than as a centralised generation source, and are growing in Australia as consumers become more active in the power system.

The uptake of DER is customer driven. The Australian Energy Market Operator (AEMO) anticipates rooftop solar capacity to double or even triple by 2040. As DER penetration levels increase and customer expectations with respect to DER use evolve, network businesses have proposed to invest in projects aimed at increasing

[1] AER, 'Assessing Distributed Energy Resources Integration Expenditure', November 2020.

DER hosting capacity and supporting a broadening range of DER services. A number of distribution network service providers (DNSPs) have prepared business cases to justify DER projects on an economic basis. This justification requires quantifying DER benefits, not just to the network in question, but to the broader electricity system, including the impact DER can have on the wholesale electricity market.[2]

The Energy Security Board has identified the integration of DER and flexible demand as one of four reform directions for market design. Its objective is to enable the integration of DER and value flexible demand so they can provide services to networks, the wholesale market and other customers.[3]

To date, networks have adopted varying methodologies and assumptions in developing business cases for DER integration expenditure, with approaches varying depending on the scale of investment and data available. The lack of consistency in approaches and varying levels of transparency around methodologies has made it difficult for us and stakeholders to assess the appropriateness of the DER integration expenditure being proposed. It has also raised questions about whether the expenditure is likely to promote outcomes consistent with the National Electricity Objective (NEO) and deliver benefits to all network customers or whether benefits are only likely to accrue to the subset of customers that have DER.

DER can provide customers with a range of benefits:

- consumers who install DER units may be able to reduce the price they pay for electricity or obtain improved reliability outcomes
- DER may also help reduce the cost of power system augmentation, helping to reduce the overall cost of supply faced by consumers
- increased penetration of DER may also help reduce the overall emissions intensity of the NEM, by displacing other more emissions-intensive generation
- consumers who install DER may benefit from a sense of empowerment, autonomy and resilience, and may be willing to pay a premium to invest in DER or accept reduced revenue from their DER investment.

Only the first two types of benefits listed above relate to factors considered in the National Electricity Objective (NEO), which we must have regard to when performing our economic regulatory functions.[4]

Distribution networks have a finite capacity to accommodate the connection of DER, such as rooftop PV systems and batteries. This hosting capacity is limited by voltage

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2 Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

3 Energy Security Board, 'Post 2025 Market Design Options - A paper for consultation, Part A', 30 April 2021.

4 The AER's obligations under the National Electricity Law are discussed further in Section 2.

and thermal constraints, which can lead to the curtailment of electricity exported from DER. Changing DER technologies and differences in maturity levels for DER present a challenge to the way we assess proposals for expenditure to integrate these technologies. Technology maturity levels are higher for solar PV and behind-the-meter batteries, and lower for newer technologies like electric vehicle (EV) vehicle-to-grid-technology.[5] The penetration of solar PV has so far been the main driver of DNSP proposals for DER integration expenditure, and therefore is the main focus of our guidance note. However, we recognise that the guidance note may need to be amended over time as other DER technologies reach maturity.

1.2 Rule reforms

On 25 March 2021, the AEMC made a draft determination for electricity and retail rules to integrate DER, such as small-scale solar and batteries, more efficiently into the grid.[6] The key aspects of the draft rules are:

- Updating the regulatory framework to clarify that distribution services are two-way and include export services. This officially recognises energy export as a service provided by distribution networks and gives consumers more influence over what export services networks deliver and how efficiently they deliver them.
- This will encourage distribution networks to deliver export services that customers value. Currently there are no financial penalties for poor network export services and no rewards for improvements.
- Enabling distribution networks to offer two-way pricing for export services, allowing them to develop options that reward owners of DER for sending power to the grid when it is needed and charging them for sending power when it is not. This is designed to reward customers for actions that better use the network or improve its operations, and helps allocate costs in a more equitable and efficient way.
- Allowing flexible pricing solutions at the network level, enabling distribution networks to develop pricing options to suit their capability, customer preferences and jurisdictional policies.

Our development of the DER integration expenditure guidance note itself is not dependent on this rule change, however there may be particular aspects of the final rule change that we should consider when we finalise the guidance note. For example, the draft rules require the AER to develop and consult on a customer export curtailment value (CECV) methodology and publish CECVs annually. We will undertake this consultation process separately after the AEMC makes its final

[5] ARENA, 'State of Distributed Energy Resources Technology Integration Report', February 2021.

[6] AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Draft rule determination', 25 March 2021.

determination. We discuss this requirement and its relationship with the VaDER methodology in section 6.

1.3 What do we want to know from stakeholders?

We seek stakeholder views on a number of aspects of our proposed DER integration expenditure guidance note. Questions in this paper are summarised below.

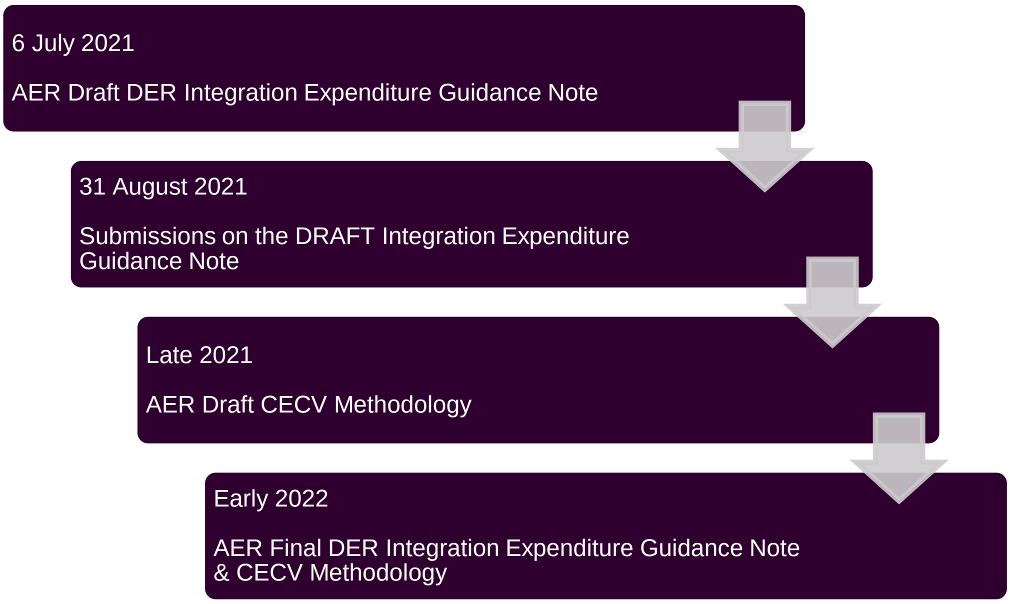
Table 1: Summary of consultation questions

Questions	
Question 1	Do you agree with the proposed guidance relating to how DNSPs should prepare a DER integration strategy?
Question 2	Should the format of the business case be prescriptive? If so, how?
Question 3	Are there particular input assumptions that should be consistent for all DNSPs?
Question 4	In what ways could DNSPs justify their assumed export limit in the base case scenario?
Question 5	Are there particular examples where DER adoption forecasts may vary between the base case scenario and the investment case?
Question 6	Do you agree with the proposed criteria for undertaking hosting capacity assessments?
Question 7	Are there other examples of approaches that DNSPs could adopt to assess network hosting capacity?
Question 8	Do you agree that the total electricity system is the appropriate system boundary for considering DER costs and benefits?
Question 9	Do you agree that the methodology used to quantify wholesale market benefits should balance shorthand and longhand approaches?
Question 10	Do you know of other examples of electricity market models or analysis tools that could be used by DNSPs to quantify wholesale market benefits?
Question 11	Do you have views on the AER's initial analysis and whether this approach could be applied in practice?
Question 12	Do you agree with the proposed principles for quantifying wholesale market benefits? Are there other principles that we should consider?

Questions	
Question 13	Do you agree with the proposed methods for quantifying network benefits?
Question 14	Do you agree with the proposed methods for quantifying environmental benefits?
Question 15	Do you agree with the proposed method for quantifying changes in DER investment?

This explanatory note discusses a number of real-world and technical issues faced by DNSPs, and for this reason we consider that DNSPs will have the greatest understanding of these issues. Nonetheless, we encourage all stakeholders to provide considered feedback and practical suggestions where possible. Submissions on the guidance note will be considered and reflected in our Final DER integration expenditure guidance note.

Figure 1: DER integration expenditure guidance note timeline



1.4 Structure of this paper

This explanatory note is structured as follows:

- Section 2 – The AER's role. This includes context for the development of the guidance note and where it will fit in the AER's expenditure assessment toolkit.
- Section 3 – Presentation of the business case. This includes our view on how DNSPs should present a concise DER integration strategy for their customers.
- Section 4 – VaDER methodology. Here we provide the VaDER methodology recommended by CSIRO/CutlerMerz and summarise our views on their specific recommendations.
- Section 5 – Defining the base case scenario. This includes our view on how DNSPs should assess existing levels of hosting capacity on their networks.
- Section 6 – Quantifying DER benefits. Here we detail our views on the types of applicable DER benefits and how DNSPs should quantify them.
- Appendix A – CSIRO/CutlerMerz recommendations.
- Appendix B – AER market modelling analysis.

2 The AER's role

2.1 Background

The National Electricity Law (NEL) requires us to perform our economic regulatory functions in a manner that will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO). The NEO is:[7]

> …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—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The NEO places an overarching requirement on the AER to make distribution determinations that will deliver efficient outcomes that benefit consumers in the long term. The revenue and pricing principles support the NEO and ensure a framework for efficient network investment exists.[8] We must take the revenue and pricing principles into account whenever we exercise discretion in making those parts of a regulatory determination relating to direct control network services.[9]

2.2 Capex objectives, criteria and factors

A distributor must include a total forecast capex that it considers is required to achieve the capital expenditure objectives, which involves:[10]

- meeting or managing the expected demand
- complying with applicable regulations
- maintaining: the reliability, quality and security of supply of standard control services; and the reliability, security and safety of the network.

The NER set out specific requirements to ensure we assess and determine expenditure proposals in accordance with the NEL, and hence give effect to the NEO. When we make a distribution determination, we must decide whether or not we are satisfied that a distributor's proposed total capex forecast reasonably reflects the capex criteria. These criteria are:[11]

i. the efficient costs of achieving the capital expenditure objectives

[7] NEL, s. 7.
[8] NEL, s. 7A.
[9] NEL, s. 16(2)(a)(i).
[10] NER, cl. 6.5.7(a).
[11] NER, cl. 6.5.7(c).

ii. the costs that a prudent operator would require to achieve the capital expenditure objectives

iii. a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

When considering whether the forecast reasonably reflects the expenditure criteria, we must have regard to the capex factors.[12]

2.3 The AER's expenditure assessment tools

Our expenditure forecast assessment guideline[13] describes the process, techniques and associated data requirements for our approach to setting efficient expenditure allowances for network businesses. It provides overarching guidance about how we assess a business's revenue proposal and how we determine a substitute forecast when required.

In 2020 we published the AER capital expenditure assessment outline for electricity distribution determinations[14], which describes the approaches we apply to assess a distributor's total capex forecast. It provides detail on the following assessment techniques:

- trend analysis
- category analysis
- bottom-up analysis
- top-down analysis
- economic benchmarking.

Further to this high-level guidance, we have published standalone guidance documents for expenditure relating to major investments, large-scale and continuous replacement programs and new technologies needed to manage electricity networks.

The Regulatory Investment Test - Distribution (RIT-D) Guideline[15] provides an additional level of guidance, and details the cost-benefit analysis that network businesses must perform and consult on before making major investments in their networks. The RIT-D aims to promote efficient investment in distribution networks in the NEM by promoting greater consistency, transparency and predictability in distribution investment decision making.

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12 NER, cl. 6.5.7(e).

13 AER, 'Expenditure Forecast Assessment Guideline for Electricity Distribution', November 2013.

14 AER, 'Capex assessment outline for electricity distribution determinations', February 2020.

15 AER, 'Application guidelines: Regulatory investment test for distribution', December 2018.

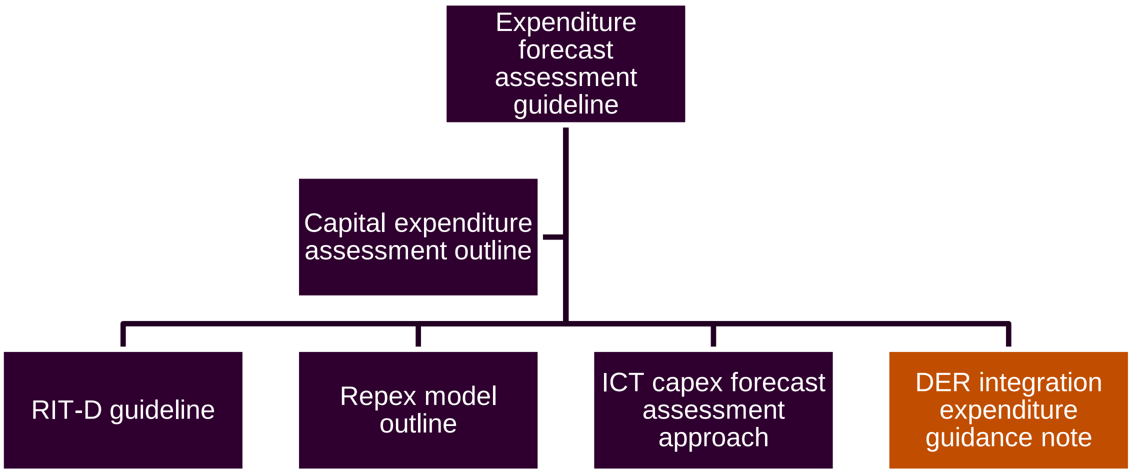
The AER repex model outline for electricity distribution determinations[16] describes the operation of our repex model, which is a statistical tool used to conduct a top-down assessment of a distributor's repex forecast.

The non-network information and communications technology (ICT) capex assessment approach[17] provides guidance on the assessment approaches we apply when assessing recurrent and non-recurrent ICT capex.

Collectively, we use the abovementioned guidance to assess the large majority of capital expenditure proposed by DNSPs. However, DER integration expenditure is not explicitly addressed by the existing guidance. DNSP proposals for DER integration expenditure have varied in nature, with different approaches taken towards the types of DER benefits and the quantification of these benefits. This is partly due to differences in network topographies, network visibility and access to network data. Our assessment of these proposals has largely been in line with our RIT-D guideline, however this guideline does not explicitly cater for investments intended to increase DER hosting capacity.

The DER integration expenditure guidance note will improve our expenditure assessment toolkit by providing clarity and certainty to DNSPs and their customers about what we expect to see in DER integration investment proposals, and how we will assess these proposals. It does not replace any of our existing guidance, but ensures that we have the right tools to assess this emerging area of network expenditure.

Figure 2: AER distribution expenditure assessment toolkit



[16] AER, 'Repex model outline for electricity distribution determinations', February 2020.
[17] AER, 'Non-network ICT capex assessment approach', November 2019.

3 Presentation of the business case

The stakeholder consultation undertaken by CSIRO/CutlerMerz revealed a number of key themes about how DNSPs prepare business cases for DER integration expenditure. One theme included the need for DNSPs to prepare a DER integration strategy—a wide-ranging approach to how distribution networks will accommodate increasing levels of DER in the future. In this section, we comment on this theme as well as our views on recommendations about the format of the business case and the selection of input assumptions.

3.1 DER integration strategy

Customer advocates suggested that DNSPs should present a coherent and coordinated approach to DER integration across their expenditure plans, tariff strategy and demand management strategy in regulatory proposals.[18]

Customer advocates were also critical of the way in which DER integration projects have been presented, making it difficult to compare DER integration expenditure. Customer advocates were particularly concerned about the way in which ICT investment proposals have been presented, making it difficult to determine what share of the investments can be attributed to DER.[19]

Customer advocates also commented that, where network benefits from DER integration are identified, they should expect to see a commensurate level reduction in expenditure within other parts of the DNSPs' capital expenditure programs and that this is not often transparent.

Our preliminary view

We recognise the concerns raised by stakeholders and consider it sensible to provide guidance for DNSPs on these issues. In particular, our guidance requests that DNSPs present a coherent DER integration strategy that is transparent in all aspects.

Relationship with other aspects of the regulatory proposal

We agree that in some recent instances, proposals for DER integration have not necessarily demonstrated a coordinated approach across the entire regulatory proposal. Proposals for DER integration expenditure should align with a broader and longer term DER integration strategy. This strategy should:

[18] CCP17, 'Response to the Value of Distributed Energy Resources stakeholder engagement workshop held by CutlerMerz and CSIRO', June 2020.
[19] Clean Energy Council, 'Clean Energy Council submission to the CSIRO-CutlerMerz Methodology Study of the value of Distributed Energy Resources', June 2020.

- Include DER penetration forecasts for the electricity distribution network over the medium to long term (at least 10 years) and the future implications of these forecasts on the network;
- Provide evidence of how tariff reform will be used to accommodate the forecasts of DER made above and reduce the need for network investment. The AEMC's draft rule change will enable export pricing and require the AER to consult on and publish Export Tariff Guidelines.[20] The rationale of cost reflective pricing is to link network tariffs to the underlying drivers of network costs. DNSPs should demonstrate how their proposed pricing structures will manage the demand for consumption and export services, make best use of existing network hosting capacity and potentially defer network investments;
- Provide a clear breakdown of the various elements of DER integration expenditure, in terms of augmentation, ICT capex and opex. Where the DNSP has identified deferred augmentation and/or replacement expenditure as a benefit associated with its proposed investment, it should demonstrate that its forecast of augmentation and/or replacement expenditure has been adjusted in a consistent manner;
- Identify any related expenditures proposed under the Demand Management Innovation Allowance;
- Identify any jurisdictional obligations outside the NER and their impact on expenditure forecasts (for example, the impact of a mandated export level for all DER customers);
- Include details of the DNSP's plan (if any) for the implementation of dynamic operating envelopes. Details may include the timing of trials, methods for capacity allocation and consumer engagement; and

We will examine opex proposals relating to DER integration in line with our base-step-trend assessment approach. While new expenditure may not be a part of base opex, normally we would expect our trend forecast, and in particular the output growth forecast, to compensate a prudent operator for the opex required to operate and maintain new assets such as those required for DER integration. However, in recent regulatory decisions we considered opex step changes relating to DER were prudent and reasonable because there is a likelihood that the output growth forecast as currently determined may not fully compensate for higher opex to address DER management.[21] Output growth as currently specified includes energy throughput, and

[20] AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Draft rule determination', 25 March 2021.

[21] AER, 'Draft decision: SA Power Networks Distribution Determination 2020 to 2025, Attachment 6 Operating expenditure', October 2019, pp. 48-50; AER, AER, 'Draft decision: Jemena Distribution Determination 2021 to 2026, Attachment 6: Operating expenditure', September 2020, pp. 64-67; AER, 'Annual Benchmarking Report, Electricity distribution network service providers', November 2020, pp. 55-57.

captures changes in the amount of energy delivered to customers, but it does not measure energy delivered into distribution networks via DER. This is an issue we are currently scoping (in the context of our benchmarking work) to determine whether there is a need to re-specify the outputs we use. Any changes to the outputs we examine may impact on our opex assessment approach in the future (noting that if the outputs are re-specified for our benchmarking work, this would also inform our assessment of base opex including existing/ongoing DER expenditures).

Evidence of historical DER integration activities

The uptake of DER has been relatively steady in most jurisdictions of the NEM and DNSPs have been dealing with DER integration either actively (by investing to increase hosting capacity) or passively (by monitoring network voltages as DER is connected). DNSPs should provide the following in their proposal for DER integration expenditure:

- Details of activities undertaken and actual expenditure in the current regulatory period to manage DER integration. These expenditures may include amounts approved under the Demand Management Innovation Allowance;
- Evidence of what these activities have delivered for customers – for example, whether current activities have increased network hosting capacity, improved network visibility or managed voltage issues.

Transparency of proposal

Aside from providing a clear breakdown of the elements of DER integration expenditure, for completeness, DNSPs should provide references to expenditure items in the reset RIN.

Question 1: Do you agree with the proposed guidance relating to how DNSPs should prepare a DER integration strategy?

3.2 Format of business case

In general, there is a four-step process that a network takes to propose a solution for a DER integration challenge and recovering costs associated with the solution:[22]

1. Identify a problem that will be solved by increasing network hosting capacity
2. Identify solution(s)
3. Assess the costs and benefits of identified/preferred solutions and the base case and choose a preferred approach
4. If the preferred approach is cost effective or otherwise justified compared to the base case, seek regulatory approval for the investment

[22] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

The proposed VaDER methodology is relevant to part of the third step – determining the value of DER that is enabled through the network improving its integration of DER.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz recommended we identify how the business case should be reported, including nomination of the methods adopted, detailed description of the counterfactual and setting out of the various components of the value stack.

Our preliminary view

Under our proposed methodology, the value of an increase in DER hosting capacity is dependent on a number of factors. In support of a proposal for DER integration expenditure, the DNSPs' business case for a DER integration project(s) should explicitly identify the following:

- Base case scenario. DNSPs should consider the proposed solution against a credible base case scenario, in line with our guidance (Section 5).
- Benefits derived from the project. DNSPs should detail the types of benefits, the value of these benefits, and how these benefits have been calculated (Section 6).

We do not propose to prescribe a particular template or format for the DER integration expenditure business case, as we encourage DNSPs to submit proposals that are innovative and best reflect their customers' expectations. However, we consider that as a minimum, the abovementioned aspects of the proposal should be clearly articulated and detailed in order for the proposed expenditure to be assessed.

In developing our proposed methodology and guidance, we have also considered stakeholder comments on the appropriate form of guidance. We agree that the guidance should be both principles-based and prescriptive-based, and consider that our proposed methodology and guidance appropriately balances these different approaches.

Question 2: Should the format of the business case be prescriptive? If so, how?

3.3 Input assumptions

Input assumptions are not a standalone feature of a DNSP's DER integration business case, however are critical to defining the base case scenario and quantifying DER benefits. As with other types of network expenditure, it is important that DNSPs select credible input assumptions in their proposals for DER integration expenditure.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz recommended that we identify the source of key input assumptions, particularly as they relate to wholesale market modelling (longhand or shorthand), DER investment costs, DER adoption rates, and any environmental values.

CSIRO/CutlerMerz also recommended that we consider commissioning, on an annual basis, the development of standard assumptions (including via electricity market modelling), which may be used as inputs to DER integration cost-benefit assessments, including:

- Long run marginal costs (LRMC) and generation profiles for standard large-scale generation types (to apply in shorthand total costs method);
- Wholesale electricity prices over a long-term investment period by region (to apply in shorthand running costs method);
- Emission intensity of generation over a long-term investment period by region; and
- DER investment costs and (where applicable) generation profiles by region.

The assumptions should be consistent with AEMO’s Integrated System Plan scenarios (including the Central scenario as a minimum).

Our preliminary view

In line with the RIT-D application guideline[23], we consider that DNSPs should use:

- Inputs based on market data where this is available and applicable
- Assumptions and forecasts that are transparent and from a reputable and independent source. In particular:
    - Material that the Australian Energy Market Operator (AEMO) publishes in developing the National Transmission Network Development Plan (NTNDP), Integrated System Plan (ISP), or similar documents should be a starting point.
    - Material that AEMO publishes in any up-to-date ISP or equivalent document, where that document has been adopted in the NER and/or NEL, should be used as a default.

[23] AER, 'Application guidelines: Regulatory investment test for distribution', December 2018.

- Up-to-date relevant information. For instance, it might be appropriate to depart from information that AEMO has published where there is evidence and good reason to demonstrate that alternative sources of information are more up-to-date or more appropriate to the particular circumstances under consideration.

We consider that a net present value analysis period of 20 years is appropriate for considering the costs and benefits of the proposed investment. This time period is in line with our assessment of repex and augmentation expenditure.

We have so far not considered commissioning the development of standard input assumptions. However, as we discuss in section 6, we will consult separately on the CECV methodology and consider the input assumptions that may be required under this methodology. This may or may not require the commissioning of standard input assumptions.

Question 3: Are there particular input assumptions that should be consistent for all DNSPs?

3.4 Options analysis

DNSPs' proposals for DER integration expenditure should demonstrate that they have considered all credible options and selected the option that addresses the identified need at the lowest cost over the life of the investment. The options considered should explore different investment timing and staging scenarios, to demonstrate the potential impacts on net economic benefits.

A credible option should be an option that addresses the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need. For DER integration investments that include augmentation expenditure, DNSPs should demonstrate the consideration of opex or ICT capex options, such as dynamic voltage management systems to improve low-voltage network visibility and better utilise existing network hosting capacity. Where the selected investment option involves a combination of these types of expenditure, DNSPs should explicitly identify the benefits associated with each component of the investment option.

4 VaDER methodology

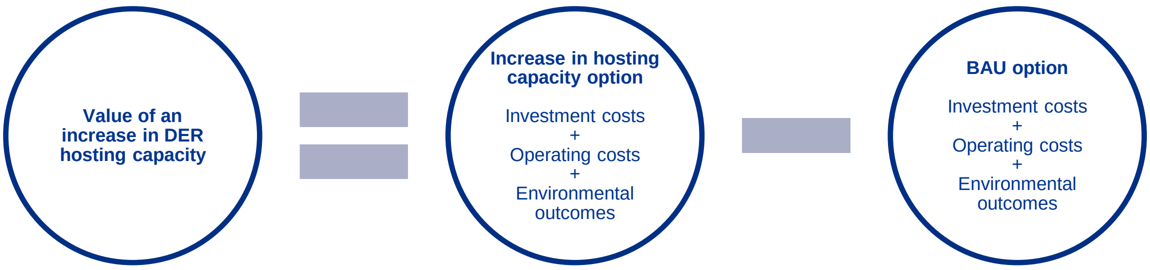
In this section we introduce the VaDER methodology and discuss our position on particular aspects of the methodology recommended by CSIRO/CutlerMerz.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz developed a methodology for determining the value of an increase in hosting capacity that compares the total electricity system costs as a result of increasing hosting capacity with the total electricity system costs of not doing so.

Electricity system costs include the investment costs, operational costs and environmental outcomes (to the extent that the environmental outcomes impart a direct cost on the system) of large-scale generation, essential system services, network assets and DER installed by customers.

Figure 3: Proposed VaDER methodology



CSIRO/CutlerMerz noted that its proposed methodology requires networks to carefully and clearly articulate their assumptions about changes in investments, operations, and environmental outcomes in both the base case and investment scenario.

Our preliminary view

Our proposed VaDER methodology is in line with this broad methodology. Table 2 summarises our position on particular aspects of the methodology and highlights where our views are different to the recommendations of CSIRO/CutlerMerz.

We consider that, regardless of the size of the proposed investment, DNSPs should use this approach to valuing benefits if they are proposing investments that increase network hosting capacity.

Table 2: Summary of AER's proposed VaDER methodology compared to CSIRO/CutlerMerz recommendation

Issue	AER position
Reporting of business case	**Agree with recommendation.** The format of the business case is not prescriptive, however DNSPs should, as a minimum, detail certain aspects of their DER integration expenditure proposal.
Base case scenario	**Agree with recommendation.** The base case represents a 'BAU' scenario and not a 'do nothing' scenario. DNSPs that adopt a static export limit in the base case scenario should demonstrate that the particular export limit is not arbitrary.
Hosting capacity assessments	**Agree with recommendation.** The method for assessing DER hosting capacity is not prescriptive, however DNSPs should demonstrate an understanding of DER hosting capacity that is proportionate to the current and expected level of DER penetration on its network.
Applicable DER benefits	**Agree with recommendation.** By defining the system boundary as the total electricity system, the applicable DER benefits include wholesale markets, network sector benefits, environmental benefits and changes in customer investment in DER.
Quantification of wholesale market benefits	**To be confirmed.** Given the likely new requirement for us to develop a CECV methodology, we have not yet provided a view on how wholesale market benefits should be quantified. We are seeking stakeholder views on the principles that will underpin the CECV methodology, and will develop the methodology under a separate consultation process.
Quantification of network sector benefits	**Agree with recommendation.** The quantification techniques vary depending on the value stream.
Input assumptions	**Agree with recommendation.** In line with the RIT-D application guideline, DNSPs should wherever possible use inputs that are based on market data, assumptions and forecasts that are transparent and from a reputable source, and up-to-date and relevant information. DNSPs should use AEMO-published input assumptions (where available) in wholesale market modelling.

5 Defining the base case scenario

As discussed in Section 3, the first step a network will take in proposing a DER integration solution is identifying a problem with integrating DER on its network. In short, the problem will be insufficient network hosting capacity to accommodate increasing levels of DER. These problems may be evidenced by voltages exceeding network limits, which can lead to inverter systems "tripping" and being unable to generate until network voltage levels return to normal.

In a cost-benefit analysis, and in order to seek funding for an investment proposal, DNSPs must demonstrate that the sum of all net benefits associated with its proposal to increase DER hosting capacity (the investment scenario) exceed the sum of all net benefits associated with the BAU option, or base case scenario.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz recommended that we identify the need to comprehensively set out a base case or counterfactual to identify the changes in both DER operation and customer investment in DER facilitated by the network investment and how the base case may relate to administrative actions (such as setting export limits).

In this section, we provide guidance for DNSPs in determining their base case scenarios as well as in undertaking hosting capacity assessments.

5.1 How to determine the base case scenario

What the RIT-D guidelines say

The RIT-D guidelines do not provide specific guidance for DER integration investments, but discuss how a base case scenario should be considered in the assessment of network augmentation projects.

If the identified need is for reliability corrective action, the RIT-D proponent may choose to select a credible option as its base case (a ‘base case credible option’). Otherwise, the base case is where the RIT-D proponent does not implement a credible option to meet the identified need, but rather continues its ‘BAU activities’ (a BAU base case).

‘BAU activities’ are ongoing, economically prudent activities that occur in absence of a credible option being implemented. For RIT-D projects concerning asset retirement, replacement or de-rating decisions, the following costs are associated with BAU activities:

- Operational, maintenance and minor capital expenditure (below the RIT-D threshold) required to allow the ageing or poor condition element to remain in service as effectively as possible for as long as possible.

- Credible BAU expenditure relating to the deteriorating asset to manage safety risk, environmental risk and equipment protection to the extent this expenditure meets legal obligations or is consistent with efficient industry practice. The RIT-D proponent should also consider any quantified 'risk costs' consistent with its BAU risk mitigation and management activities and with reference to our 'industry practice application note for asset replacement planning'.

The RIT-D guidelines provide the following example to demonstrate how the base case scenario should be selected.

Augmentation project to provide a net economic benefit

A RIT-D proponent is considering a network augmentation to avoid an increase in the expected volume of unserved energy as load at a particular location on its network grows.

No mandatory service standard or regulatory instrument is driving the augmentation to avoid expected load shedding. Therefore, the identified need must be driven by an increase in the sum of consumer and producer surplus in the NEM. Accordingly, the base case for the RIT-D assessment must refer to a state of the world in which the RIT-D proponent does not pursue the augmentation project nor implement any other credible option to meet the identified need (the BAU base case).

While this BAU base case option in the face of ongoing load growth may eventually result in what appears to be unrealistically high volumes of expected unserved energy, what is important from the perspective of a RIT-D assessment is that the base case provides a clear reference point for comparing the performance of different credible options.

The RIT-D assessment would then involve comparison of the net economic benefit available from:

- The augmentation option as against the BAU base case; to
- Other relevant credible options, as against the BAU base case.

The preferred option is the option that maximises the net economic benefit across the NEM. If no credible option yields a net economic benefit, this means the BAU base case represents the best course of action.

Setting export limits

DNSPs may restrict DER exports in parts of their network that experience voltage and/or thermal constraints. The AEMC observed that these restrictions are being imposed as basic connection size or export limits, with some customers facing very low or even zero export limits in areas of the network with high levels of solar penetration.

As DER penetration increases in the future, the instances of DNSPs restricting export are likely to increase.[24]

To date, most networks have defined the base case as an option which requires them to reduce export limits to a low or zero level rather than allow tripping to occur. We agree with CSIRO/CutlerMerz and consider that this approach does not align with the RIT-D base case guidance of not implementing "any other credible option". Further, adopting this approach to deal with DER growth may lead to suboptimal outcomes where exports are artificially constrained.

Changes to technical standards have reduced the likelihood that solar PV installations will cause technical or safety issues for DNSPs, as exports will automatically reduce or stop as capacity limits are reached. Most networks have already mandated new rooftop PV and battery inverters connected be configured with the Volt-VAr response modes defined in AS4777.2 inverter standards. CSIRO/CutlerMerz concluded that the base case could allow inverter systems to "trip" at times where DER exports exceed hosting capacity.[25]

The AEMC also noted that the imposition of static export restrictions (e.g. an export limit of 2 kW for all households in a particular network area) could lead to uneconomic outcomes. For example total system costs could be lower if more of the existing solar PV installations (providing zero marginal cost energy) are able to inject energy into the electricity system instead of other more expensive energy sources such as grid scale conventional generators.[26]

CSIRO/CutlerMerz noted that the use of static export limits as the base case should be treated with caution. This is because the lower the assumed static export limit, the higher the benefits of the business case. It suggested that where a static export is used as a base case, it should be demonstrated as to why that particular static export limit is appropriate (and not arbitrary).[27]

In recent years, DNSPs have made new investments and adopted innovative techniques to better understand the behaviour of their networks. In most cases, expenditure has been funded under total capex and opex allowances in our distribution determinations, however funding has also been provided via the Demand Management Innovation Allowance (DMIA).[28]

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[24] AEMC, 'Integrating distributed energy resources for the grid of the future, Economic regulatory framework review', 26 September 2019.

[25] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

[26] AEMC, 'Integrating distributed energy resources for the grid of the future, Economic regulatory framework review', 26 September 2019.

[27] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

[28] The DMIA aims to provide incentives for DNSPs to conduct research and investigation into innovative techniques for

CitiPower and Powercor recently proposed the use of a Dynamic Voltage Management System (DVMS) as part of their solar enablement business cases, while United Energy noted that it had already implemented a DVMS throughout its network.[29] This has allowed it to remotely and dynamically adjust voltages at the zone substations, meaning it can lower voltages at peak solar times and then increase them again later. United Energy noted that this has proved to be a low cost way to accommodate more solar and it intends to continue operating it as part of its business as usual practice.[30]

DNSPs are also exploring the use of dynamic operating envelopes in order to maximise the value of DER. A dynamic operating envelope is a principled allocation of the available hosting capacity to individual or aggregate DER or connection points within a segment of an electricity distribution network in each time interval. It essentially provides upper and lower bounds on the import or export power in a given time interval for either individual DER assets of a connection point.[31] CitiPower, Powercor and United Energy (CPU) noted that they are developing dynamic operating envelopes to better manage DER. This includes ensuring DER operates within the bounds of the network's capacity to minimise disruption and ensure customers get fair access. It also supports new business models such as virtual power plants by providing visibility on the amount of DER available to them at any given point in time.[32]

Energex's Solar Enablement Initiative, run by the University of Queensland in partnership with other stakeholders, is a relevant example of a project funded under the DMIA. Under this project an innovative state estimation algorithm was developed, implemented and tested for monitoring medium voltage electricity distribution networks. This project aims to provide an improved understanding of electricity network behaviour to maximise the capacity of new solar PV installations and their export into the Australian grid, thereby enabling an increase in the percentage of renewable energy connected to the grid.[33]

The Energy Security Board has sought views from stakeholders on the role that DNSPs will play in balancing system limits. It noted that, to ensure the physical limits of the network can be kept in balance and manage congestion, DER will need to respond to signals from distribution networks about emerging system issues such as local congestion or low demand. By moving to a more dynamic mechanism, DNSPs would

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managing demand. It also aims to enhance industry knowledge of practical demand management projects and programs through the publication of annual project summary and expenditure reports.

29 Further detail on the DVMS and its application to assessing hosting capacity is provided in section 5.

30 United Energy, 'Business case 6.06: Enabling residential rooftop solar', January 2020.

31 Blackhall, L., 'On the calculation and use of dynamic operating envelopes', ARENA/ANU evolve Project M4 Knowledge Sharing Report, accessed April 2021.

32 CitiPower, 'Revised proposal 2021-26', December 2020.

33 Energex Limited, 'Energex Demand Management Innovation Allowance Report AER Submission 2017/18', August 2018.

take the additional responsibility for the creation of dynamic limits and publish these limits in a way that retailers and aggregators can access and enforce them.[34]

DER adoption forecasts

CSIRO/CutlerMerz commented that networks rarely should and rarely will change their DER adoption forecasts between a base case scenario and the investment scenario. Networks should invest to integrate DER based on reasonable assumptions of DER adoption and not in a way that is actively incentivising additional DER adoption. It suggested that the base case should identify a challenge in DER integration that occurs because forecasted DER adoption is realised and yet no new network solution is implemented. In other words, in the base case, no new limit is placed on DER connections, no new tariffs are adopted, no changes are made to existing inverter standards, and no other network expenditure is undertaken to address the increase in DER adoption that surpasses network hosting capacity.

Notwithstanding, CSIRO/CutlerMerz noted that where network investments are significant enough to fundamentally alter the return on investment for a DER customer, such a circumstance may warrant a change in DER forecasts between scenarios. For example, if a network proposes to invest in new network infrastructure (e.g. larger transformers) that would enable networks to raise their default connection limits, this may warrant a revised DER forecast. However, CSIRO/CutlerMerz commented that such examples will be relatively uncommon.[35]

Our preliminary view

We agree with CSIRO/CutlerMerz's comments on the use of static export limits. Although DNSPs may assume a static export limit in their base case scenario, they should demonstrate that this limit is not arbitrary. DNSPs could undertake sensitivity analysis to demonstrate that the investment case is preferable when compared to a range of business as usual export limits. This may demonstrate that the assumed export limit is not selected arbitrarily.

DNSPs that employ more advanced techniques to understand network behaviours (such as a DVMS or dynamic operating envelopes) should demonstrate how these techniques have informed the export limit selected in the base case scenario.

DNSPs should provide a baseline forecast of DER adoption in terms of number, capacity and type of DER systems adopted over the investment life. In general, our assumption is that networks will invest to integrate forecast DER and not actively recruit and grow DER adoption beyond projected adoption, however there may be

[34] Energy Security Board, 'Post 2025 Market Design Options - A paper for consultation, Part A', 30 April 2021.

[35] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Frequently asked questions', CutlerMerz, CSIRO, Australia.

some exceptions to this. These exceptions may occur when it is assumed that the proposed investment will automatically permit additional DER exports. For example, a proposed investment to increase hosting capacity may enable an increase in default connection export limits and allow existing DER owners to export more electricity.

Where DER adoption forecasts do not match those in the investment case, DNSPs should provide evidence of analysis to support their assumptions. This analysis should detail whether the assumed difference in DER adoption forecasts is due to customers purchasing DER, existing DER owners being provided additional capacity to export electricity, or both. We note in section 6.5 that where DER adoption forecasts are different, DNSPs may need to quantify the costs and benefits associated with changes in customer investment in DER.

Question 4: In what ways could DNSPs justify their assumed export limit in the base case scenario?

Question 5: Are there particular examples where DER adoption forecasts may vary between the base case scenario and the investment case?

5.2 Guidance for assessing hosting capacity

As CSIRO/CutlerMerz noted, DER integration business cases depend in large part on hosting capacity: the amount of DER a network views its current system can sustain, and what it believes it will be able to accommodate in the future given some investment.

CSIRO/CutlerMerz also commented on the relationship between defining the base case scenario and assessing the network's hosting capacity. It noted that perhaps the largest issue in relation to identifying the base case is accurately identifying the amount of DER a network could host absent any investment.

DNSPs have varied levels of knowledge about the level of hosting capacity on their networks, which is largely driven by differences in network visibility and access to data. However, as discussed above, DNSPs are using a variety of techniques to better understand the behaviour of their networks, and we expect that knowledge of DER hosting capacity will continue to improve as DNSPs further develop and implement these techniques.

Differences in network visibility are due to differences in DER penetration across networks. Networks with greater DER penetration are more likely to experience voltage or thermal violations, and so have been required to undertake analysis and invest in sophisticated techniques to understand their existing hosting capacity. Conversely, where the uptake of DER has been slower, DNSPs have not improved network visibility to the same extent, and have a relatively limited understanding of their hosting capacity. This lack of knowledge can be to the detriment of DER owners, as the network is more likely to adopt a conservative approach to setting exports.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz recommended the AER consider developing guidance for networks to follow in assessing the hosting capacity of their networks.

It noted that there is not a uniform way in which networks conduct hosting capacity assessments, and stakeholders in the regulatory process have little insight (and poor knowledge of the fundamental challenge) into how networks assess hosting capacity. The ability of networks to understand hosting capacity limits is a key input into their DER integration business cases, and is also critical for many other businesses, particularly DER providers. The business prospects of solar installers, virtual power plant (VPP) developers and aggregators – among others – depend upon the ability of customers to connect and export DER.

Consequently, given the importance of hosting capacity assessments to DER integration business cases, the impact on the future business of networks and other industry participants, and the lack of uniformity and transparency in current hosting capacity assessments, it suggested that the AER consider providing guidance on how networks should analyse hosting capacity and how to communicate those findings to stakeholders.[36]

5.2.1 How to assess hosting capacity

There is no common approach used by networks to determine the hosting capacity of their networks. As noted above, this is largely due to data limitations and differences in LV network visibility across DNSPs. Analysis of hosting capacity can be deterministic or probabilistic and can be undertaken using a range of modelling and analysis methods. In this section we summarise DNSP approaches to assessing hosting capacity and consider whether these approaches can and should be adopted by all DNSPs.

SAPN

SAPN's LV Management Strategy was the basis for its proposed DER integration expenditure in its 2020-25 regulatory proposal. As part of this strategy, it engaged EA Technology to determine the maximum headroom available on SAPN's electricity network to accommodate the connection of DER before the occurrence of voltage and/or thermal violations.

At a high level, the SAPN/EA Technology approach was as follows:

1. The 75,530 LV areas in the network were classified into 15 categories, based on key factors that influence hosting capacities.

[36] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

2. Field audits were undertaken of a number of representative sample LV feeders in each category, to capture detailed electrical information and refine the category definitions.
3. Detailed electrical models of the representative feeder samples were built using DIgSILENT Power Factory. These models were then used to simulate network conditions using representative customer load profiles at increasing levels of DER penetration, to determine the penetration levels at which voltage and thermal limits are reached.
4. The outputs of this process were used to build an abstract whole-of-network hosting capacity model, taking into account statistical variability within each network category.

DIgSILENT Power Factory

DIgSILENT Power Factory is a power system analysis software package commonly used in the analysis of transmission and distribution systems. EA Technology used version SP1 (2018), which offers a toolbox that allows Quasi-Dynamic simulation which is used for time-based (medium to long-term) simulations.

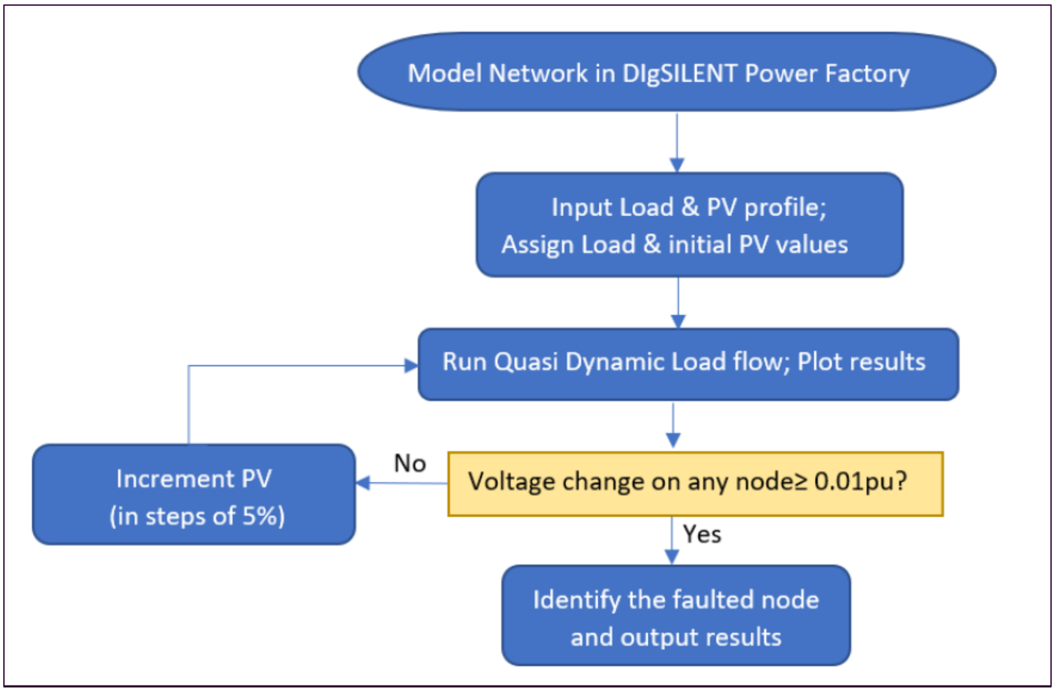
The Quasi-Dynamic tool in Power Factory allows for analysis of the network under user-defined load/generation profile for a specific snapshot of the network during individual time steps of the simulation. The tool performs multiple load flow calculations for a user-specified duration, with user-defined time step sizes.

For the first step, SAPN nominated specific networks under each category to be modelled in Power Factory. EA Technology noted that the nominated networks were representative of a large proportion of networks within each category, and SAPN validated these models by interrogating its own data and ensuring they were representative networks rather than outliers.

For the third step, SAPN did not have access to advanced metering infrastructure (AMI) data due to the prevalence of older ‘accumulation’ meters in South Australia, so it was necessary to estimate customer load profiles. Based on the average consumption from metering data a uniform load with a peak consumption of 1.2 kW at 0.98 lagging power factor was used for individual customers connected to the LV networks. The loads were configured to a 24 hour, half-hourly profile based on the load profile of a typical summer day. In the LV networks, PV panels were assumed to be uniformly distributed across individual customers within the network, and the capacity of each PV generator was initially set to a maximum of 1.2 kW while modelling the base network.

Figure 4 shows the steps followed by EA Technology to determine the limiting amount of generation that can be allocated in each network. The output plot of the Quasi-Dynamic analysis was analysed to check for voltage and thermal violations on the network. The PV was incremented in steps during each iteration. The iteration was repeated until the power generation resulted in an increase in voltage that breached the upper voltage band (here shown as a 1% increase). These steps were repeated for each network for different power factors of load and generation. The results were noted for loads at unity power factor and a power factor of 0.98 (lagging) and for PV generation with unity power factor and power factors of 0.98 and 0.93 (lagging) to model the behaviour of legacy (pre-December 2017) PV systems and current and future AS4777.2 Volt-VAr compliant systems.

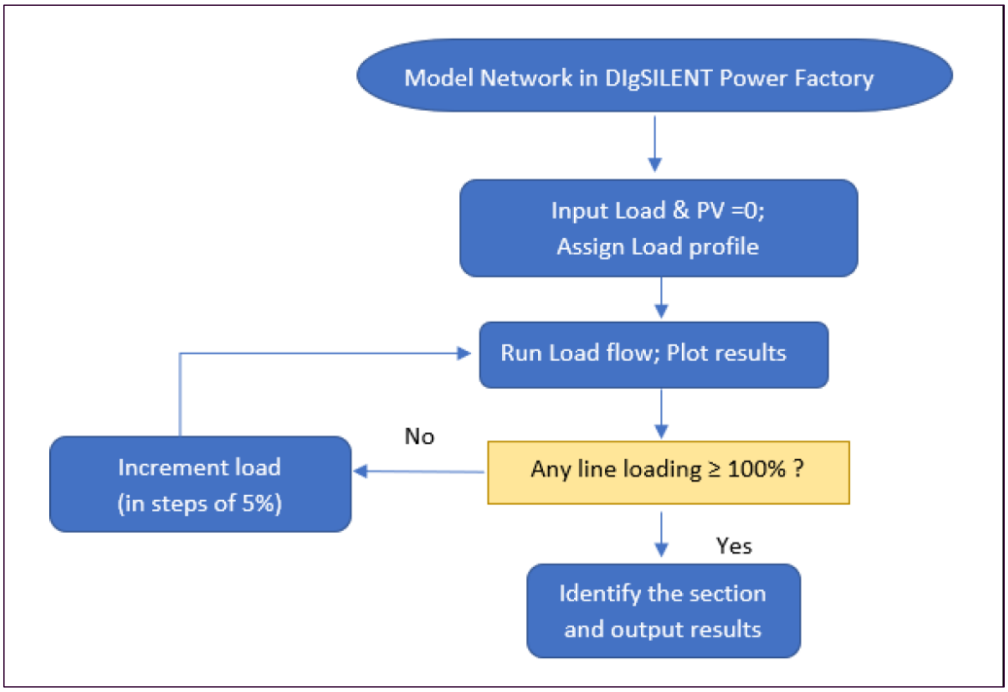
Figure 4: SAPN/EA Technology, steps taken to determine the limiting amount of PV



Source: SA Power Networks, Supporting document 5.22.1: EA Tech - LV Management Strategy AN 1 DER Hosting Capacity Assessment, 23 November 2018.

In addition to the voltage violation, several runs of load flows were carried out on the model. Load flow for the snap shot was carried out on the network to establish the thermal limit of the network. For this analysis, the individual load flows were conducted at the time of day when the load was highest. The instantaneous PV generation at that time was set to zero. This process is summarised in figure 5.

Figure 5: SAPN/EA Technology, steps taken to determine the thermal limit of the network



Source: SA Power Networks, Supporting document 5.22.1: EA Tech - LV Management Strategy AN 1 DER Hosting Capacity Assessment, 23 November 2018.

In addition to the methodology described above, SAPN considered the following scenarios and sensitivities:

- The impact of reactive power injection by PV inverters was analysed in a series of sensitivity studies.
- An annual study was undertaken to determine what proportion of time voltage exceedances occurred. This analysis informed the Transform Model[37] what proportion of time voltage exceedances occurred over the duration of a year.
- Investigation of the impact of voltage rise from the 11 kV networks on the LV networks due to adjacent LV networks having high PV penetration. Based on the results from this analysis, the allowable voltage rise on the representative feeders within the Transform Model was refined.
- Random allocation of PV locations. This demonstrated that the random allocation of PV to customer nodes within any given representative network did not have a material impact on the calculated results.

[37] The Transform Model is discussed further in section 6.

- Different network interventions were selected to estimate the amount of capacity which they create. These included uprating transformer, infilling transformer, splitting feeder and rebalancing phases.

The Quasi-Dynamic analysis (performed in DIgSILENT Power Factory) produced a report detailing the maximum and minimum voltages observed at customer nodes through the duration of the simulation. The results included the total reverse power following through the main transformer at the verge of network voltage exceedance, the location(s) of the network breakage, time of day, the total installed capacity of PV generation that caused the voltage exceedance and the allocated load at the time. These results were directly imported into the Transform Model for further analysis.

CitiPower, Powercor and United Energy

In its 2021-26 regulatory proposals, CPU proposed a solar enablement program, setting out its plans for an efficient level of expenditure to enable the connection of rooftop solar PV generation.

CPU developed a model that used over 38 billion actual AMI voltage readings to examine how often solar will trip on its transformers to 2029. It then compared the cost of removing a voltage constraint with the benefits as measured by the value of solar energy. CPU's solar enablement model was developed in Python, an open source statistical and programming tool. In further detail, the approach to determining the amount of solar tripping was as follows[38]:

1. Voltage readings were gathered for every 15 minutes from 2018/19 for each of its National Meter Identifiers (NMI). Using this data it found the amount of solar tripping across its networks by counting the reads for solar customers above the threshold at which inverters trip.
2. The forecast of commercial solar was removed from total forecast solar and the remaining solar forecast was attributed to each distribution transformer based on customer numbers, historical locational solar growth and saturation limits.
3. Load flow modelling was undertaken to determine the voltage rise from new solar connections, on both different conductor types and lengths. This modelling assumed all new customers have Volt-VAr inverter settings applied. The voltage rise per customer was based on the actual conductor type.
4. The distribution of actual voltage readings was shifted based on the voltage rises and solar forecast discussed above.
5. CitiPower and Powercor considered the impact of a DVMS to set the voltage threshold used in the model to determine when tripping occurs. It noted that a DVMS is able to change voltage set points at zone substations in response to changes in voltage levels. Currently, this can be undertaken manually, however

[38] CitiPower, 'Business case 6.02: Enabling residential rooftop solar', January 2020.

solar exports vary regularly and it is not possible to manually monitor voltages and change set points continuously. Therefore, it only uses this functionality occasionally for system security. To apply the impact of DVMS in its modelling, it set the threshold at which solar will be constrained in its model higher than the actual level It valued solar that is lost once inverters trip rather than also including the reduction to active power output from the new inverter settings.

As discussed above, CPU's modelling sought to identify the least cost way to address a network constraint by first considering the impact of new inverter settings and implementing a DVMS. It then considered whether voltages could be reduced by tapping transformers down, by examining the minimum voltages experienced on that transformer. CPU's analysis compared the net present value of the solar electricity that would be constrained to the average cost of remediating a constraint to assess whether it was economic to unlock the constrained solar.[39]

Other approaches

The Australian Renewable Energy Agency (ARENA) is supporting a number of innovative projects under its Network Hosting Capacity funding round.[40] The 'Advanced Planning of PV-Rich Distribution Networks Study', led by the University of Melbourne in partnership with AusNet Services, is one such project that is particularly relevant. This project is seeking to develop analytical techniques to assess residential solar PV hosting capacity of electricity distribution networks by leveraging existing network and customer data.[41]

ARENA notes that the project will perform detailed studies on distribution networks with different residential solar PV penetrations to capture the correlations between customer data and corresponding penetrations. Results from these studies will be used to define analytical techniques to rapidly estimate the hosting capacity of networks. The techniques will be validated using smart meter data from networks where PV penetrations are known. The findings will be used to draw planning recommendations to cost-effectively increase the hosting capacity of distribution networks.

Notably, in stage two of the project, an innovative analytical technique was defined to calculate the solar PV hosting capacity of a residential area (LV customers connected to the same distribution transformer). Using the developed detailed network models, growing PV penetrations in a horizon of five years were simulated to create a large realistic smart meter data set. The analytical technique was then applied to this data and tested for different PV penetrations. The authors noted that the findings show that

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[39] Section 6 details CPU's methodology for valuing the solar energy.

[40] Australian Renewable Energy Agency, 'Distributed energy projects awarded nearly $10 million', February 2019.

[41] Australian Renewable Energy Agency, 'Advanced Planning of PV-Rich Distribution Networks Study', accessed April 2021.

the proposed analytical technique provides adequate estimations of PV hosting capacity, making it possible for DNSPs to have a faster and simpler alternative to time-consuming approaches that require full network models.[42]

In summary, the methodology was as follows:

1. For a given number of days, the daily smart meter data from all customers in a given LV network are extracted from the smart meter database.
2. The smart meter data are analysed and cleaned from missing and inconsistent values. Then, the maximum voltage recorded for each day is identified and the corresponding active powers are added up. Finally, a new dataset is produced containing the maximum voltage and the corresponding aggregated power for each day.
3. The new dataset is then used to train a supervised univariate regression model which corresponds to the hosting capacity estimation model for the analysed LV network.

The hosting capacity estimation model estimates the aggregated active power that can lead to voltages outside a pre-determined upper limit. This value, in turn, can be used to calculate the additional PV capacity that can be hosted by the LV network.

The report highlights that the volume of smart meter data used to produce the hosting capacity estimation model plays an important role. More data helps to capture the variance of a large sample of network conditions, thus increasing the model's estimation accuracy.

Our preliminary view

Overall, we consider the methodologies used by SAPN and CPU to assess hosting capacity to be thorough and proportionate. SAPN's methodology demonstrates a strong focus on the verification of input data based on real-world and engineering expectations, as well as the use of scenario and sensitivity analysis to 'sense check' model outputs. Although SAPN's analysis was limited by the unavailability of AMI data, it uses reasonable assumptions for customer load profiles and the distribution of PV panels across customers in the network.

CPU's approach makes use of its investment in smart meters by utilising a large volume of AMI data. This data enables a detailed analysis of transformer performance across the network and allows the networks to model the impact of low cost options to enable more solar before considering network augmentation.

In developing a business case for a proposal to increase DER hosting capacity, DNSPs must demonstrate that existing DER hosting capacity has been thoroughly

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[42] Australian Renewable Energy Agency, ['Advanced Planning of PV-Rich Distribution Networks - Deliverable 2: Innovative Analytical Techniques'](), October 2019.

analysed. Under our proposed VaDER methodology, DNSPs must demonstrate that net customer benefits under the investment case (to increase hosting capacity) exceed those under the base case, and properly defining the base case relies on a good understanding of the existing level of hosting capacity. In considering whether DNSPs have demonstrated the best possible understanding of DER hosting capacity, we will consider the following criteria:

- **DER penetration** – as an overarching principle, the level of hosting capacity analysis undertaken by DNSPs should be commensurate to current and forecast levels of DER penetration on the distribution network, as well as the amount of hosting capacity to be unlocked by the proposed investment. That is, DNSPs with high levels of DER penetration (both currently and forecast over the price control) should demonstrate a comprehensive understanding of DER hosting capacity. This is because a greater number of current and prospective DER owners are impacted by the DNSP's decision to invest or not invest in increasing DER hosting capacity.
- **Investment in network visibility** – DNSPs that have made investments to better understand the nature of their LV networks (in terms of voltage and thermal constraints) should demonstrate a thorough understanding of DER hosting capacity. DNSPs that have been previously funded for investments and activities of this nature should demonstrate value for money to their customers, and part of this value is the presentation of a suitable base case scenario to compare proposed investments against.
- **Access to AMI data –** DNSPs with access to AMI data should make use of this data in their assessment of DER hosting capacity. Studies such as the 'Advanced Planning of PV-Rich Distribution Networks Study' have demonstrated that AMI data may be used in econometric models to estimate DER hosting capacity and therefore DNSPs with access to AMI data may not necessarily need to undertake more advanced network modelling.

We consider that these criteria reflect the positive aspects of the approaches adopted by SAPN and CPU, but also provide the possibility for DNSPs to undertake more innovative approaches to assessing network hosting capacity.

Question 6: Do you agree with the proposed criteria for undertaking hosting capacity assessments?

Question 7: Are there other examples of approaches that DNSPs could adopt to assess network hosting capacity?

6 Quantifying DER benefits

Under the proposed VaDER methodology DNSPs must identify which costs and benefits associated with an increase in hosting capacity can be included. In this section we outline the types of DER benefits and value streams that we consider may be enabled by investments to increase DER hosting capacity. We also provide our rationale for the methodologies used to quantify these DER benefits.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz considered the implications of where the system boundary is drawn in assigning costs and benefits of DER integration investments, and listed three potential system boundaries:

1. To the meter: At the boundary of the electricity system (representing costs that all electricity consumers pay) but excluding any behind the meter assets;
2. Total electricity system: Extending the boundary to behind the meter, where DER assets are included; or
3. Society: All benefits to society are considered.

CSIRO/CutlerMerz considered that it is most appropriate to use the total electricity system approach - effectively extending the boundary to behind the meter - and consider any DER owners as producers of electricity. It noted that the NEO places an overarching requirement on the AER to make distribution determinations that will deliver efficient outcomes to the benefit of electricity consumers in the long-term. [43] In well-functioning competitive markets, the benefits of investments that lower total costs will flow through to customers in the long term in the form of lower prices. Table 3 compares the inclusion or exclusion of DER value streams depending on system boundaries.

[43] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

Table 3: CSIRO/CutlerMerz comparison of DER value streams depending on system boundaries

Cost/benefit category	To the meter	Total electricity system	Society
Wholesale market benefits	Included	Included	Included
Network sector benefits	Included	Included	Included
Environmental benefits	Included if they impose a direct cost or confer a financial benefit on non-DER resources	Included if they impose a direct cost or confer a financial benefit on all resources	Included even if no government imposed costs or benefits
Intangible benefits	Excluded	Excluded	Included
Change in DER investment	Excluded	Included	Included
Government subsidies for DER	Excluded (all DER costs and subsidies excluded)	Excluded	Excluded

Our preliminary view

We agree that the total electricity system is the appropriate system boundary for considering the costs and benefits of DER integration investments. This approach is consistent with the value streams considered in the RIT-D application guidelines and we consider is likely to contribute to the achievement of the NEO.

However, for some benefit types, there are practical issues and challenges that we should consider under this approach. In addition, the value that customers place on intangible (or non-monetary) benefits is not quantified and therefore not considered under the RIT-D application guidelines. In the following sections we discuss these benefits and value streams and how DNSPs should quantify them in their DER integration expenditure proposals.

Question 8: Do you agree that the total electricity system is the appropriate system boundary for considering DER costs and benefits?

6.1 Wholesale market benefits

DER integration can deliver the following wholesale market benefits:

- Avoided marginal generator short-run marginal costs (SRMC) – Increased DER generation substitutes for generation by marginal centralised generators, which may have higher SRMC, in the form of fuel and maintenance costs.
- Avoided generation capacity investment – Increased DER generation reduces the need for investment in new/replacement centralised generators.
- Essential System Services (including FCAS) – Increased DER capacity enables more DER participation in ESS markets, reducing investment in new/replacement centralised ESS suppliers.

CSIRO/CutlerMerz noted that in the context of valuing additional DER in the wholesale market both SRMC and LRMC are relevant. SRMC are costs that are incurred as a function of output, whereas LRMC include the components of SRMC plus fixed costs which do not vary with output. It also noted that the electricity market is subject to reasonably long cycles of divergence from LRMC. During periods of excess supply, generators are willing to supply at any price that clears the market above their SRMC. During periods of excess demand, they have market power and are in a position to set the price above their LRMC. All benefits must satisfy the requirement that they calculate the change in the sum of consumer surplus plus producer surplus.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz recommended that we identify how wholesale market benefits should be calculated (including reference to shorthand methods) and an expectation that longhand market modelling should be undertaken for investments over a threshold amount or that will realise a threshold of DER capacity.

CSIRO/CutlerMerz suggested both a longhand and shorthand method for quantifying generation sector benefits. The longhand approach involves undertaking electricity market modelling, which enables the impact of the change in DER services on the wholesale market to be quantified in terms of both the avoided investment and avoided operational costs.

What is electricity market modelling?

Electricity market modelling seeks to identify how investment and dispatch of generators in an electricity market is likely to occur over time and impact wholesale market prices.

Electricity market models are used to identify how a change in market structure or market rules are likely to impact market outcomes or to derive assumptions with respect to future wholesale market prices to inform investment decisions. Market modelling is also used to determine optimal development pathways under AEMO's Integrated System Plan and the Electricity Statement of Opportunities process.

There are several proprietary models which have been developed for the National Electricity Market. Most models consider iterative bidding and portfolio optimisation by market participants in simulating electricity market behaviour but are driven by differing assumptions with respect to participant behaviour and exogenous factors (such as fuel prices). The uptake and operation of DER is an exogenous input to electricity market models.

The shorthand approach refers to methods that can be undertaken using readily available spreadsheet software and data either created by the network or in the public domain. CSIRO/CutlerMerz proposed that a shorthand method may be used (with the first two criteria met to qualify)[44]:

- Where investment is relatively small such that the cost of the longhand approach is likely to materially erode the benefits
- Where the investment is likely to give rise to a small amount of DER capacity relative to the energy market it will impact (less than 0.1% of total capacity in the state)
- For any other investment, as a screening test to determine the likelihood that an investment will return a positive business case.

CSIRO/CutlerMerz proposed two shorthand approaches and provided worked examples of these[45]:

- Total cost method: for evaluating the avoided investment in the wholesale market by considering the total (long run marginal cost) of the corresponding technology investment avoided; and

[44] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.
[45] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

- Running cost method: when the total cost method is not applicable, wholesale market prices can be a proxy for short run marginal cost for the previous year, and a discount factor can be applied and adjusted over time to account for likely changes in average prices in the relevant time period.

Our preliminary view

As we noted in section 1, the AEMC's recent draft determination will require the AER to develop and consult on a CECV methodology and publish CECVs annually. These values will help guide the efficient levels of network expenditure for the provision of export services and serve as an input into network planning, investment and incentive arrangements for export services. These values will be different from values of customer reliability, as they are not intended to measure the value to customers of having a more reliable export service or consumption service but rather the detriment to customers and the market from the curtailment of exports.[46] The draft rule provides an objective that the CECV methodology and CECVs should be fit for purpose for the current and potential uses of these values that the AER considers to be relevant.[47]

Our current view is that the CECV methodology will provide the method for calculating wholesale market benefits, which unlike other aspects of the VaDER methodology, may be calculated independently. Given the importance of ensuring consistent approaches across the VaDER and CECV methodologies, we are unable to provide guidance on how these values should be calculated until we develop the CECV methodology for consultation. We note that if the rule change is finalised, we will be required to consult on and develop the CECV methodology under the Rules consultation procedures and calculate and publish initial CECV estimates by 1 July 2022. In the rest of this section we provide our initial views on the recommendations made by CSIRO/CutlerMerz.

We consider that in practice, it is unlikely that DER integration expenditure proposals will meet the criteria suggested by CSIRO/CutlerMerz for undertaking shorthand approaches. In particular, we consider it highly unlikely that the cost of undertaking electricity market modelling would materially erode the benefits associated with any proposed DER integration proposal. Looking at some recent examples, SAPN estimated its proposed LV management program will provide a net benefit of approximately $40 million (up to 2035)[48], and CitiPower estimated its proposed solar enablement investment will provide a net benefit of approximately $32 million (up to 2050).[49]

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[46] AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Draft rule determination', 25 March 2021.

[47] Amending electricity rule schedule 2, introducing new NER rule 8.13(a).

[48] SA Power Networks, 'Supporting document 5.18: LV Management Business Case', January 2019.

[49] CitiPower, 'Business case 6.02: Enabling residential rooftop solar', January 2020.

Not meeting the proposed criteria or threshold does not mean that we should automatically discount the value of shorthand methods. However, shorthand methods are generally conservative, and there is a reasonable risk that shorthand methods may be too simplistic and may overstate the benefits of proposed DER integration investments. This would lead to inefficient investment to the detriment of electricity consumers. Given the recent and forecast uptake of DER, it is likely that network expenditure on DER integration solutions will continue to grow, so it is important that DNSPs accurately measure the benefits of their proposed investments.

We also recognise that, as raised by stakeholders, developing a highly accurate modelling tool may provide accuracy but is likely to be more costly and complex to implement. We should aim to strike an appropriate balance between simple but potentially inaccurate methods and accurate but overly complex (and potentially expensive) methods. This balance could be achieved by:

- improving and further developing shorthand methods (such as those recommended by CSIRO/CutlerMerz) so that the risks of overstating benefits are mitigated; or
- simplifying longhand methods, by replicating the workings of electricity market models using simple and readily available software (to the extent this is possible).

In the following section we discuss existing and potential approaches to electricity market modelling which may be explored further as we develop the CECV methodology.

Question 9: Do you agree that the methodology used to quantify wholesale market benefits should balance shorthand and longhand approaches?

6.1.1 How to undertake electricity market modelling

In response to CSIRO/CutlerMerz, most DNSPs considered there was value in the AER providing a calculation tool or providing a value to be used in calculating wholesale market benefits. This view was also shared by consumer groups, who considered this would provide greater transparency and consistency in outcomes. One customer advocate did however note that there may be value in diversity of approaches to ensure that the method evolves over time as the industry evolves.[50]

There are examples of DNSPs undertaking electricity market modelling in support of their DER integration expenditure proposals. There is also academic literature that demonstrates potential approaches to estimating the impact of DER on wholesale electricity prices and dispatch costs. In this section we compare and contrast these examples and discuss the strengths and weaknesses of different approaches.

50 Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

SAPN

In its 2020-25 regulatory proposal, SAPN's LV management strategy relied on analysis from a number of sources. This analysis derived inputs into a model developed by EA Technology called the "Transform Model".[51] The steps followed under this strategy are summarised below.

1. Undertake DER hosting capacity study, to determine the maximum headroom available on SAPN's LV network to accommodate the connection of DER before the occurrence of voltage and/or thermal violations.[52]
2. Develop strategic choices or approaches that would manage hosting capacity and ensure quality and reliability of supply on SAPN's network.
3. Calculate the cost of curtailing DER to facilitate a cost-benefit analysis.
4. Identify new operational systems and capabilities and assess the functionality and costs required to deliver the strategic option under consideration.
5. Undertake Transform Modelling network analysis.
6. Undertake cost-benefit analysis.

In general, the step-by-step approach taken by SAPN is prudent and broadly reflects the four-step process for proposing a solution for a DER integration challenge that is discussed in section 3. In this section we focus on the third step of SAPN's approach, as it relates to the quantification of wholesale market benefits.

SAPN engaged HoustonKemp to estimate the value of grid-sourced energy over the period to 2035 that would be displaced by the relief of constraints in SAPN's distribution network that allow for greater exports from solar PV installations and/or reduced constraints on the operation of VPPs. HoustonKemp also developed a fit-for-purpose model of the operation of VPPs that can be used to estimate the periods in which the operation of a VPP may be constrained under the current network configuration.

To estimate the value of avoided dispatch costs, the approach was to value the additional distributed generation exports in each dispatch period based on the marginal cost of grid-sourced generation that would otherwise be expected to generate in that dispatch period. These marginal costs of grid-sourced generation were considered the dispatch costs saved by additional distributed generation, since they represent the generators that would have otherwise been called to supply the market.

EA Technology's Transform Model required a single dispatch cost value to be inputted. To calculate this value, HoustonKemp determined marginal cost traces for each trading interval in the period 2018-2035, averaged these to obtain annual values, and then

[51] https://eatechnology.com/engineering-projects/the-transform-model/

[52] Further detail on SAPN's approach to hosting capacity assessments is discussed in section 5.

averaged these annual values. To facilitate a cost-benefit analysis, the Transform modelling exercise calculated the amount of constrained export to the network that would be faced by DER across each strategic option and investment scenario. HoustonKemp's values (in $/MWh) were multiplied by the forecast magnitude of constrained energy from the Transform Model (MWh) to calculate the total market impact of constraining exports under a given strategy.[53]

HoustonKemp's methodology for estimating the value of grid-sourced energy by any increase in distributed generation exports on SAPN's network was:

1. For the base year (2017), identify the generators that were 'marginal' (price setters) at each five-minute (dispatch) interval in South Australia.
2. Calculate the projected marginal costs for each of these generators ($/MWh), for each year to 2035, based on AEMO assumptions.
3. Assign sequential blocks of dispatch intervals with similar generator marginal costs to 'generator categories', approximately based on fuel type of marginal generator.
4. Derive traces for the marginal cost of generation for each generator category for each dispatch interval for each year to 2035, based on two scenarios – one where the mix of marginal generators continues to reflect that in 2017, and one where the mix changes over the period.
5. Adjust the estimated marginal cost traces for the projected impact of future increases in solar PV in South Australia.
6. Calculate final estimates of avoided dispatch costs ($/MWh) for solar PV exports and VPP charging and discharging, in a form suitable for input to the model being used by SAPN.

At step 5, HoustonKemp noted that AEMO's price setter data used to calculate the marginal generators in 2017 considered demand net of distributed solar PV, and as such, distributed solar PV was never considered marginal in the database. It made an adjustment to its analysis to account for the expected role of solar PV in acting as the marginal generator in practice in the future. Specifically, in addition to considering a scenario where solar PV was never the marginal generator, it considered scenarios where solar PV was the marginal generator in 2%, 5% and 10% of trading intervals.

SAPN's methodology implies the following modelling target question: what is the avoided dispatch cost in South Australia per MWh of PV generation in South Australia? The final estimates of average avoided dispatch costs ranged from $46.85/MWh (in the 10% marginal scenario) to $50.86/MWh (in the 0% marginal scenario).

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[53] SA Power Networks, 'Supporting document 5.21: EA Tech - LV Management Strategy', December 2018.

In our draft decision for SAPN[54] we commented that while the analysis is comprehensive, the use of a single value is a limitation as it may not reasonably reflect the behaviour of the market or the impact of the network's limitations. PV inverters will be constrained at different times and for varying lengths of time based on the density of PV in an areas, local demand relative to local PV generation, and the characteristics of the network such as topography. Similarly, the marginal cost of wholesale generation differs over any given day, such that the marginal cost of generation and localised PV constraints need to be aligned to determine the value of foregone PV export. We noted that there would be significant value in undertaking a post-implementation review to demonstrate the benefits realisation over time.

Transform Model

The Transform Model presents a parametric model of an entire electricity distribution network. This model builds on data from a number of sources, including:

- A range of hosting capacities from prototypical representations of different feeder categories
- A range of solutions for improving hosting capacity that a network operator may employ (This includes network-side solutions, such as new transformers, and non-network solutions, such as tariffs or customer storage)
- Electricity consumption profiles of different customer classes
- Generation/demand profiles of different customer classes
- Uptake rates for different DER (incorporating solar PV, battery storage and electric vehicle behaviour)

The Transform Model then overlays the anticipated future demand that will be placed upon the network from various DER, based on forecasts published by AEMO. In instances where network feeders breach their hosting capacity limits, the Transform Model simulates the technical and economic choices that a network operator will have to make to resolve the hosting constraint.

Victorian DNSPs

In its 2021-26 regulatory proposals, CPU proposed solar enablement programs due to forecast increases in solar PV penetration. They noted that this was expected to cause localised network voltages to rise, which may cause solar inverters to trip off as a safety measure that prevents the solar PV system from producing and exporting.[55]

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[54] AER, 'Draft Decision: SA Power Networks Distribution Determination 2020 to 2025, Attachment 5 Capital expenditure', October 2019.
[55] CitiPower, 'Business case 6.02: Enabling residential rooftop solar', January 2020.

Jacobs was engaged to analyse the market benefits of these programs. For its analysis, it defined market benefits as the reduction in total generation costs (fuel and operating and maintenance costs) and the value of carbon abatement. In contrast to SAPN's target question, CPU sought to estimate the NEM-wide avoided dispatch cost per MWh of PV generation in Victoria.

Jacobs used the "PLEXOS" model to develop forecasts for electricity generation costs and wholesale prices in the NEM. A baseline market model was specified in PLEXOS and the total baseline cost of generation over the project period (2020-2029) was established, as well as an alternative market model where the distributed solar generation is fully enabled and exportable to the grid. These results were then compared to the baseline model outputs and used to calculate the difference in total generation costs and carbon emissions against a set carbon price.

PLEXOS

PLEXOS is a sophisticated stochastic mathematical model developed by Energy Exemplar which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming that co-optimises generation dispatch, transmission power flow and ancillary services and integrates them with optimisation of hydro-electric generation and emissions abatement.

There are four key tasks performed by PLEXOS:

- Forecast demand profiles over the planning horizon, given the historical load profile, expected energy generation and peak loads.
- Schedule maintenance and pre-compute forced outage scenarios.
- Model strategic behaviour, if desired, based on dynamic gaming models.
- Calculate hourly or half-hourly unit dispatch given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, other operating restrictions (such as spinning reserve requirements) and variable operating costs including fuel costs and price impacts of abatement schemes.

Jacobs' approach to estimating the difference in total generation costs between a market model with and without solar enablement was:[56]

[56] CitiPower, 'Attachment 054 - Jacobs, Market Benefits for Solar Enablement - Final Report', January 2020.

1. Project the expected solar uptake and applicable solar generation by development of 30-minute interval load traces (in MW) of small-scale rooftop solar PV for each network.
2. Model the expected tripping of solar inverters in each network and calculate the potential loss of PV generation to be supplied to each network.
3. Specify two rooftop PV load traces: one 'Baseline' PV load trace and one 'Solar Enablement' load trace.
4. Scale both load traces to include PV uptake for the other two Victorian DNSPs.
5. Develop an up-to-date market model in PLEXOS.
6. Run the model twice: once with the Baseline and once with the Solar Enablement PV trace. All other things remained equal in the PLEXOS model.
7. Extract the total generation cost per annum and the carbon emissions per annum and compare both mode outputs.

Jacobs found that the weighted average market benefit was $35.22/MWh and the weighted average carbon abatement benefit was $11.48/MWh, making the total benefit approximately $47/MWh over the FY2020-29 period. This market benefit differs significantly from the benefits estimated by Jemena and AusNet Services (approximately $100/MWh), which adopted the applicable FiT of between 10-12 cents per KWh.[57]

AusNet Services engaged Frontier Economics to assess whether the Victorian feed in tariff (FiT) is a reasonable proxy for the value of removing constraints on solar exports on its network. Frontier Economics acknowledged there are some limitations with using the FiT (for example, the FiT is only a single year estimate), but concluded that it represents a reasonable proxy for the value of solar exports.[58] Several stakeholders raised concerns with using the FiT in the context of continued growth in solar PV uptake, and the likelihood of negative pool prices in Victoria based on the Queensland and South Australia experience. We agreed that the use of the 2019-20 FiT was problematic and likely overstated the economic benefits of pursuing network augmentation.[59]

Stakeholders also expressed concern with the methods used by the DNSPs to value solar PV exports in their modelling. In its advice to the AER, the Consumer Challenge Panel 17 (CCP17) commented on methodologies used by the Victorian DNSPs to

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57 In addition to the value of energy, these market benefits capture an estimate of the carbon emission reduction value.

58 Frontier Economics, 'Value of relieving constraints on solar exports', 16 October 2019 (published on the AER website in 'AusNet Services - Capex - Other Supporting Documents - updated July 2020).

59 AER, 'Draft Decision: AusNet Services Distribution determination 2021 to 2026, Attachment 5 Capital expenditure', September 2020.

value PV export.[60] It noted that the assumed value of rooftop solar exports used in the capex modelling is, in the case of at least one DNSP, over the life of the network asset, and it did not consider these an appropriate assumption given the life of the customer's PV system is generally little more than 10-15 years. Similarly, the Energy Users' Association of Australia (EUAA) submitted that the value of DER may be overstated, highlighting that in both South Australia and Queensland in the last twelve months, at times in the middle of the day increased solar PV can have no value or a negative value with the incidence of negative pool prices increasing.[61]

CCP17 also provided comments on the Victorian DNSPs' solar enablement business cases. It noted that central to the analysis is the diversified level of peak net export that drives voltage rise, and the DNSPs' expectation of 5 kilowatts of peak net export for 95% of customers, especially over a local network area, was excessive. It suggested that most customers will seek to self-consume some energy at least, and it had not observed any evidence that customers with solar PV will change behaviour to meet this level of export (being close to the full rated output of a typical residential PV system).

Academic literature

In addition to market modelling undertaken by DNSPs, there is a range of academic research which estimates the impact of renewable energy on wholesale electricity prices and dispatch costs that provides some meaningful insights. The literature in this area is broadly focused on two methodologies: econometric modelling and supply curve modelling.

Forrest and MacGill (2013) analysed the merit order effect of wind generation in wholesale electricity markets.[62] The analysis used a range of econometric techniques to estimate the relationship between wind generation and NEM spot prices, using 30 minute data for a two year period from March 2009 to February 2011. The analysis was undertaken at the regional level within the NEM, for South Australia and Victoria, the two regions with the highest volumes of wind generation. It found that wind generation reduced the wholesale price in South Australia by $8.05/MWh and in Victoria by $2.73/MWh, when applied to the average wholesale price in each region over the two year period.

Mountain, Percy, Kars, Saddler and Billimoria (2018) analysed wholesale electricity market prices in South Australia and used econometric methods to determine the

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60 CCP17, 'Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021-26', 10 June 2020.

61 Energy Users Association of Australia, 'Submission: AusNet Services EDPR 2021-26', June 2020.

62 Forrest, S., MacGill, I. (2013). Assessing the impact of wind generation in wholesale prices and generator dispatch in the Australian National Electricity Market, Energy Policy 59:120-132.

relative impact of renewables, coal generation closure and gas prices.[63] Half-hourly generation price and volume data was used in linear regressions to solve for regression coefficients. These coefficients were interpreted as the $/MWh change in wholesale prices per MWh change in wind and solar generation dispatched. The modelling built on previous analysis by providing insight into seasonal trends in the wholesale market, with modelling undertaken for each season of the year.

The input data used included the half-hourly South Australian spot price (excluding price spikes above $1000/MWh), half-hourly wind generation data, interconnector export, operational demand (all sourced from NEMReview[64]) and estimates of half-hourly rooftop solar production.[65] It was reported that the model accurately estimated spot prices and the coefficients on the key variables of interest in the regression were statistically significant at 1 per cent in almost all of the 192 half-hourly regressions (48 half hour intervals for four seasons).

The model estimated wholesale price reductions at the rate of $0.26 per MWh, per one MWh of additional solar production in winter. In summer, additional solar has a smaller impact on prices than in winter, due to the typically higher level of gas generation (and hence less efficient and thus more expensive gas production at the margin) that is displaced by solar generation in winter than in summer. It found that, when looking at the 2018 average spot price of $90 per MWh, the 1,110 GWh of solar generation in South Australia reduced prices by $10/MWh.

Using a supply curve modelling approach, McConnell (2013) calculated the likely reduction of wholesale prices due to increased PV generation through the merit order effect on the Australian National Electricity Market.[66] In the absence of empirical generation data, the study used a solar PV generation model to estimate the PV energy generated from a 1 kW PV system in different NEM regions. It then considered the NEM as a single region and used a simplified energy dispatch model to estimate how the NEM-wide dispatch price reacted to the change in the energy demand level in each dispatch interval. From an energy trade value perspective, the modellings results indicated that the value of 5 GW of PV installation due to the merit order effect could reach $1.2 billion and $628 million in 2009 and 2010, respectively.

Most of the academic literature has focused on the impact of DER on wholesale electricity prices rather than dispatch costs. Although potentially more simplistic than some of the market modelling tools used by DNSPs, the academic literature to date provides valuable insights into the drivers of wholesale market prices across different

[63] Mountain, B. R., Percy, S., Kars, A., Saddler, H., and Billimoria, F. (2018). Does renewable electricity generation reduce electricity prices? Victoria Energy Policy Centre, Victoria University, Melbourne, Australia.

[64] https://app.nemreview.info

[65] Using the Bureau of Meteorology Gridded Solar Irradiance dataset.

[66] McConnell, D., Hearps, P., Eales, D., Sandiford, M., Dunn, R., Wright, M., Bateman, L. (2013). Retrospective modeling of the merit order effect on wholesale electricity prices from distributed photovoltaic generation in the Australian National Electricity Market, Energy Policy 58:17-27.

regions of the NEM, as well as the impact of increases in wind and solar production. It also demonstrates that changes in wholesale prices vary across seasons, due to changes in the level of DER generation and the marginal generator over time.

AER analysis

We have undertaken preliminary analysis, aiming to build on existing research, and focusing on the supply curve modelling approach demonstrated by McConnell (2013). Under this approach, our empirical analysis of avoided dispatch costs uses merit order data to estimate the avoided dispatch cost (calculated using the marginal dispatch cost) as a result of rooftop PV generation. A summary of our methodology and results is provided in Appendix B.

This analysis extends existing research by estimating the impact on dispatch cost instead of wholesale prices. The RIT-D application guidelines note that we will consider changes in fuel consumption arising through different patterns of energy dispatch as a relevant market benefit.[67] This supply curve modelling approach is preferred over econometric modelling for the following reasons:

- Most academic literature that uses econometric modelling is focused on the impact of DER on wholesale electricity prices rather than avoided dispatch costs, making it difficult for us to adapt an existing robust model.
- Using a linear regression model would require us to trade-off model robustness with model simplicity. That is, there is no guarantee that the underlying relationship between the independent variable (such as the dispatch target of centralised generators) and PV energy output is linear. Further, adopting a more sophisticated econometric model may lead to modelling results that are difficult to interpret.
- Although it may be computationally slow, the supply curve modelling approach provides a number of benefits. It reflects the actual underlying data and is relatively simple to interpret. Unlike econometric models, there is no concern about non-linearity between variables, no assumption is required about the stationarity of variables and there is no need to deal with outliers or smooth the data.

It is important to emphasise that the analysis undertaken so far is empirical and could equally be undertaken using simpler methods (for example, using wholesale electricity prices). Our modelling approach can be applied to estimate the avoided dispatch cost for each region in the past given historical levels of PV generation. In order to use a model such as this to estimate avoided dispatch costs in the future (with increased PV generation), it may be possible to test scenarios where existing generators react to the additional PV generation. Since the market environment will change year-to-year, a longer sample period may help to achieve more reliable modelling results.

[67] AER, 'Application guidelines: Regulatory investment test for distribution', December 2018.

The model target question is fundamental to the potential application of this methodology. In the analysis we have described, our target question has been region-specific and in line with SAPN's target question, i.e. what is the avoided dispatch cost in SA per MWh of PV generation in SA? For this reason, our results were relatively similar to SAPN's estimate of avoided dispatch cost, but different to CPU's.

We have previously noted that the increasingly distributed nature of electricity and the increased potential to orchestrate DER has increased the potential for distribution-level investments to provide material benefits to different regions of the NEM.[68] Considering that CPU's target question was different to SAPN's, we also estimated the NEM-wide avoided dispatch cost per MWh of PV generation in Victoria, in line with its approach. Based on 2019/20 data, we found that there was approximately 96 GWh of additional PV generation in Victoria, which accounted for 4% of the actual PV generation. This additional PV generation avoided approximately 24 GWh of generation in Victoria and a further 72 GWh of generation in other regions (because of interconnector behaviours). Overall, our estimate of the NEM-wide avoided dispatch cost per MWh of PV generation in Victoria was $41.72, a figure similar to CPU's estimate. Notwithstanding the similarity in the modelling results, we should also note the key difference between our modelling methodology and CPU's. CPU's methodology is a simulation-based forecasting approach, built using a range of forecasts and assumptions about market dynamics and participants' behaviours. Our modelling methodology is retrospective and relies on historical market data.

We consider that this initial analysis may inform our development of the CECV methodology, subject to further consultation with stakeholders.

Our preliminary view

Although a standard modelling approach may be preferred by some stakeholders, we do not consider it appropriate to prescribe a particular model or methodology prior to our consultation on the CECV methodology. Reflecting on the modelling techniques used by DNSPs in their regulatory proposals, we consider that models such as Transform and PLEXOS are powerful and fit-for-purpose tools. Our main concerns have been in their transparency and, in particular, the appropriateness of inputs into these models. We consider it is useful for us to continue evaluating different modelling techniques in order gain a better understanding of the strengths and weaknesses of these approaches.

Our current view is that the use of a FiT as a proxy for the value of solar exports is not appropriate under the VaDER methodology. We agree with CSIRO/CutlerMerz's view that the FiT is not likely to be fit for purpose, due to:

- The constant rate not being able to reflect future changes in the electricity market;

[68] AER, 'Application guidelines: Regulatory investment test for distribution', December 2018.

- The constant rate not reflecting that the additional DER generation enabled by the investment will have a unique profile depending on the type of investment; and
- The constant rate including components which may not fall within the boundaries of consumer and producer surplus.[69]

We are interested in stakeholder views on the principles that should underpin the method for calculating wholesale market benefits. We consider that transparency and economic/technical rationale should form the basis of the final approach to quantifying wholesale market benefits under the CECV methodology:

- Transparency
  - The chosen modelling method should be transparent and the model logic should be reviewable by a third party.
  - Assumptions and input values in the model should be clearly stated and source references provided. If additional data or analysis is relied on to determine input values, this data/analysis should be accessible.
- Economic/technical rationale
  - The type of model and its specification should be relevant to both the assessment of DER export value and the time period that is being modelled. The model should consider the time periods during which solar is typically constrained (prior to network investment), rather than a general period over which solar PV operates.
  - Analysis should take account of the mix of electricity generation and variation in this mix over time.
  - The modelling time period should be relevant to the type of investment being proposed. For example, if the investment has a long service life, the model should consider the variation in DER export value over the period of recovery of the proposed investment.

Question 10: Do you know of other examples of electricity market models or analysis tools that could be used by DNSPs to quantify wholesale market benefits?

Question 11: Do you have views on the AER's initial analysis and whether this approach could be applied in practice?

Question 12: Do you agree with the proposed principles for quantifying wholesale market benefits? Are there other principles that we should consider?

[69] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

6.2 Network benefits

DER integration can deliver the following network benefits:

- Avoided/deferred transmission augmentation – Increased DER capacity may reduce the amount of load supplied from within distribution networks, reducing peak demand at transmission connection points and avoiding/deferring transmission augmentation.
- Avoided/deferred distribution augmentation – Increased DER capacity increases the amount of load supplied from within local distribution networks, reducing peak demand at upstream network assets and avoiding/deferring augmentation of these assets.
- Distribution network reliability – DER can supply individual customers and/or local networks after network faults, where it can be islanded, reducing unserved energy and outage duration.
- Avoided replacement/asset derating – Increased DER capacity can lower the average load on network assets, enabling asset deratings and when replacement is required, smaller, cheaper assets can be installed.
- Avoided transmission losses – DER generation can supply loads within the distribution network, reducing the supply from centralised generators connected to distribution networks by transmission lines, which avoids energy being lost to heat when transported over transmission lines.
- Avoided distribution losses – Increased DER generation can supply nearby loads, reducing the distance the energy travels across the distribution network compared to centralised generators, which reduces the amount of energy lost to heat when transported over distribution lines.

6.2.1 How to quantify network benefits

CSIRO/CutlerMerz noted that, for network benefits of additional DER, there is generally only one way to calculate network benefits which is the normal network planning processes as described in the RIT-T and RIT-D guidelines. However, there may be some circumstances where a network might use an average avoided cost rather than a specific avoided project cost and this could be considered a shorthand approach.[70]

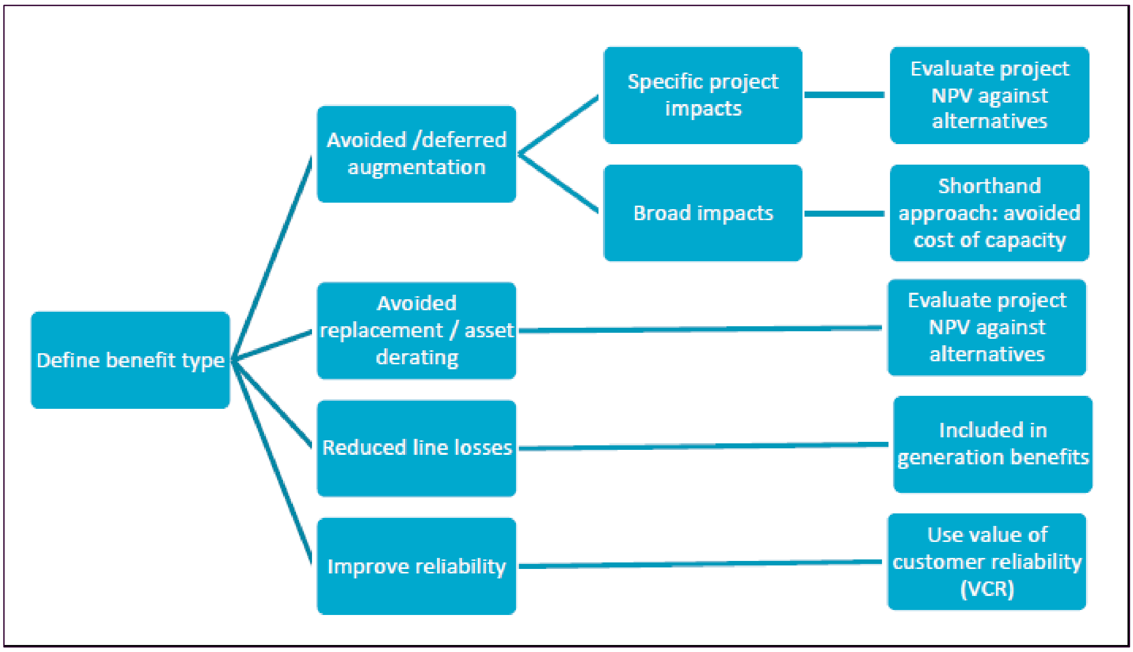
[70] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

CSIRO/CutlerMerz recommendation

CSIRO/CutlerMerz recommended that we identify the preconditions under which network benefits may be included and references to applicable methods contained within existing AER guidance.

Its recommended approach for selecting network methods is based on the type of network benefit and whether it derives from a specific network project affecting specific assets or a broad-based project with wider and longer lasting impacts. Figure 6 summarises the recommended method selection process for network sector benefits.

Figure 6: CSIRO/CutlerMerz recommended method selection process, network sector benefits



Our preliminary view

Our methodology for valuing network benefits is in line with this recommendation.

The methodology that DNSPs should use for quantifying network benefits depends on the particular value stream and which of the following is enabled by the proposed network investment:

- Increase in variable energy generation – energy generated by passive DER systems with a profile dictated by technology type and resource conditions (e.g. solar PV, wind)
- Increase in flexible energy generation – energy generated by active DER systems with a profile dictated by tariff structures and/or market conditions to maximise customer returns (e.g. batteries)

- Increase in flexible capacity – active DER capacity available to provide services to wholesale markets (generally Essential Services such as FCAS) or network services including demand management (e.g. batteries and demand response).

Avoided/deferred augmentation

Increased DER capacity may lead to avoided/deferred transmission augmentation as it may reduce the amount of load supplied from within distribution networks and reduce peak demand at transmission connection points. It may also lead to avoided/deferred distribution augmentation, as it increases the amount of load supplied from within distribution networks and may reduce peak demand at upstream network assets.

If the proposed investment enables an increase in variable energy generation or flexible energy generation, DNSPs may only quantify avoided/deferred transmission and distribution augmentation where generation aligns with the peak[71], and do so based on the RIT-T guidelines, RIT-D guidelines, or average LRMC approaches.

If the proposed investment enables an increase in flexible capacity, DNSPs may quantify the avoided/deferred augmentation for investments based on the RIT-T, RIT-D or average LRMC approaches.

In deciding whether to adopt an approach under the RIT-D/T guidelines or an average LRMC approach, DNSPs should consider whether there are known short-medium term constraints (specific project impacts). If so, DNSPs should follow the RIT-T or RIT-D guidelines. If there are no known constraints (but rather broad impacts), DNSPs may adopt a shorthand approach such as calculating the average LRMC. To do this for avoided/deferred transmission augmentation, each kW of reduced peak demand contributed by the distribution network to the transmission network is valued at the annualised LRMC of the transmission network. For avoided/deferred distribution augmentation, each kW of reduced peak demand is valued at the annualised LRMC of the distribution network. Both values can be estimated from historical demand growth and augmentation expenditure data.

As noted in section 3, where a DNSP quantifies avoided/deferred augmentation as a benefit associated with a DER integration investment, it should demonstrate that its augmentation expenditure forecast has been adjusted in a consistent manner.

[71] Or the probability that it will align with the peak, based on the timing of past maximum demand events.

Deferred and avoided network augmentation with specific project impacts

A DNSP forecasts that increased solar PV connections in a number of areas of its network will cause voltages to increase. These areas of the network will require future augmentation to accommodate further increases in solar PV and maintain voltage compliance.

As part of its base case scenario, the DNSP forecasts a program of capex that involves low voltage line augmentation, circuit rearrangement and transformer replacement. For simplicity, we assume that the capex program will occur in 2 years, at a total cost of $15 million. The current discount rate is 4%.

The DNSP investigates implementing a dynamic voltage management system (DVMS), allowing it to adjust voltages at zone substations. The cost of the DVMS is $1 million and the investment would occur in the first year. It estimates that this option will avoid the need to undertake half of the capex program in the base case scenario (costing $7.5 million), and defer the remaining capex program by 2 years.

- In the base case scenario, in year 2:

$$PV = \frac{\$15\ million}{(1.04)^2} = \$13{,}868{,}343$$

- In the investment case, in year 4:

$$PV = \frac{\$7.5\ million}{(1.04)^4} = \$6{,}411{,}031$$

The benefit of the delayed and reduced transformer augmentation program due to the implementation of the DVMS is:

$$\$13{,}868{,}343 - \$6{,}411{,}031 = \$7{,}457{,}312$$

The net benefit is reduced by the cost of implementing the DVMS:

$$\$7{,}457{,}312 - \frac{\$1\ million}{(1.04)^1} = \$6{,}495{,}773$$

Avoided replacement/asset derating

Increased DER capacity can lower the average load on network assets, enabling asset deratings and when replacement is required, smaller, cheaper assets can be installed. DNSPs may quantify these benefits where the proposed investment to increase hosting capacity leads to changes in other parts of the network where:

- peak demand is not growing over time at the relevant network asset
- peak demand coincides with times when DER exports are enabled
- network asset longevity can be improved by reducing loads.

Any potential benefits in this category are likely to be asset specific, and so DNSPs should quantify the avoided replacement benefits based on the RIT-D guidelines.

As noted in section 3, where a DNSP quantifies avoided replacement/asset derating as a benefit associated with a DER integration investment, it should demonstrate that its replacement expenditure forecast has been adjusted in a consistent manner.

Reduced line losses

Increases in DER generation may result in avoided transmission and distribution losses. DER generation can supply loads within the distribution network, reducing the supply from centralised generators connected to distribution networks by transmission lines, which avoids energy being lost to heat when transported over transmission lines. It can also reduce the distance the energy travels across the distribution network compared to centralised generators, which reduces the amount of energy lost to heat when transported over distribution lines.

The avoided transmission and distribution losses should be built into the calculation of wholesale market benefits. The avoided losses themselves are not an economic benefit, but the avoided generator SRMC is an economic benefit.

Improve reliability

DER can supply individual customers and/or local networks after network faults, where it can be islanded, reducing unserved energy and outage duration.

This benefit is only quantifiable if the proposed investment enables an increase in flexible energy generation and/or flexible capacity, and only where additional batteries have been enabled. Specifically, this value stream may be quantified where:

- The proposed investment includes or incentivises additional investment in battery storage (which would otherwise not be installed)
- The additional battery investment is able to be islanded during a fault
- Outages of up to a few hours are common.

The benefit can be calculated by assessing the expected value of unserved energy for each customer that has invested in additional battery capacity as a result of the network's DER integration investment. The assessment of avoided unserved energy must consider whether the battery will have the necessary stored charge to meet household demand for the duration of a typical outage. This could be done by reviewing the proportion of outages that occur at different times of the day and assuming no benefit for the proportion of outages that occur between certain hours (such as late at night when the battery has finished discharging). Each avoided kWh of unserved energy is to be valued using the appropriate VCR value.

Question 13: Do you agree with the proposed methods for quantifying network benefits?

6.3 Environmental benefits

Environmental benefits broadly encompass the benefits of avoided greenhouse gas emissions due to additional DER. In line with CSIRO/CutlerMerz's recommendation, these benefits may only be quantified if there is an identifiable tax, levy or other payment associated with environmental or health costs which producers are required to pay or where jurisdictional legislation directs DNSPs to consider the impact of these externalities and has provided a value that is to be used. Under the total electricity approach to system boundaries, these benefits may be included if they impose a direct cost or confer a financial benefit on all resources (including both DER and non-DER).

Where there is a jurisdictional requirement to do so, renewable energy targets and/or a potential carbon price for generators should be incorporated into the DNSP's calculation of wholesale market benefits. If there is a jurisdictional requirement to consider the price of carbon, the DNSP should calculate the carbon benefits associated with its proposed investment. CSIRO/CutlerMerz noted that where this is the case, the DNSP will need to identify an emission intensity profile for each half hour period over the investment lifespan, and a carbon value adopted consistent with the value set jurisdictionally. While AEMO does not currently publish this information, an electricity market model could be used to derive this information consistent with AEMO's Integrated System Plan (ISP) Central Scenario.

Question 14: Do you agree with the proposed methods for quantifying environmental benefits?

6.4 Intangible benefits

Some stakeholders identified potential intangible consumer benefits such as customer empowerment, autonomy and resilience, noting that these are not necessarily able to be captured within the standard economic cost benefit framework. We acknowledge that some customers may value these intangible (or non-monetary) benefits and these benefits may factor into their decisions to purchase DER.

Under our proposed methodology, other perceived (intangible) DER benefits are excluded from the VaDER calculation. We agree with the position of CSIRO/CutlerMerz, which noted that "intangible benefits are part of the decision-making process of DER investment, as they are for many investments and purchases. Nevertheless, research indicates that most customers primarily invest in DER for financial benefits, and our assumption is that the value of intangible benefits not already captured within the methodology is small".

Although intangible benefits may accrue to DER owners, either through a willingness to pay a premium for investment in DER or to accept reduced revenue as a producer of electricity, these benefits are external to the electricity system.[72] Further, in line with the RIT-D principles, credible options should maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.[73]

6.5 Change in DER investment

DER owners are considered to be producers of electricity, and this value stream recognises the changes in the costs that they face. That is, an investment to increase DER hosting capacity may incentivise more or less customer investment in DER than would have otherwise been the case. It represents a negative benefit (or a cost) where a network investment encourages additional DER (for example, customers purchase larger solar systems), and a positive benefit where a network investment encourages less customer investment (for example, customers no longer purchase batteries).

We agree that, to appropriately balance the costs and benefits of DER integration expenditure, the costs that DER customers pay should be considered in a cost-benefit analysis. This is in line with the total electricity system approach. However, we recognise there is a practical challenge with adopting this approach. CSIRO/CutlerMerz noted that when applying this approach, the accuracy of DER adoption forecasts for both the base case and an investment case become significantly more important. DER forecasts used today by AEMO in the ISP, for example, do not consider any impacts from network constraints, and networks might struggle to credibly identify such forecasts.

SAPN's submission noted that customer investment in DER will not be materially incentivised by distributors investing in network hosting capacity. SAPN also noted that a customer's decision to invest in DER of sufficient size and configuration to generate excess energy to export will primarily be incentivised by market participants such as retailers and VPPs who directly deal with and sell DER products and services to customers.[74]

72 AEMC, 'Applying the energy market objectives', 8 July 2019.
73 NER, cl. 5.17.1(b).
74 SAPN, 'Submission to methodology study - Value of Distributed Energy Resources (VaDER)', 25 September 2020.

We note that the treatment of DER investment costs only changes the calculation of benefits if the DNSP varies its forecast of DER adoption between the base case and the investment case. As discussed in section 5, in general we expect that DER adoption forecasts in the base case scenario should match those in the proposed investment case. However, there may be exceptions which may permit DNSPs to quantify the change in DER investment as a benefit.

DNSPs should include an estimate of the costs and benefits associated with changes in DER investment when:

- they assume different DER adoption forecasts in the base case scenario and investment case; and
- any of the difference is due to customers purchasing DER.

DER subsidies that the customer receives should be netted off from investment costs.

Question 15: Do you agree with the proposed method for quantifying changes in DER investment?

Appendix A: CSIRO/CutlerMerz recommendations

Publication of guidance note

It is recommended that the AER prepare a guidance note or practice guide setting out a principles-based approach to preparing business cases for DER integration. The guidance note or best practice guide should identify as a minimum:

- The types of DER benefits which may be included and how these may be stacked for different types of DER integration investments depending on the DER services enabled;
- How wholesale market benefits should be calculated (including reference to shorthand methods) and an expectation that longhand market modelling should be undertaken for investments over a threshold amount or that will realise a threshold of DER capacity;
- The preconditions under which network benefits may be included and references to applicable methods contained within existing AER guidance;
- The need to comprehensively set out a base case or counterfactual to identify the changes in both DER operation and customer investment in DER facilitated by the network investment and how the base case may relate to administrative actions (such as setting export limits);
- The source of key input assumptions, particularly as they relate to wholesale market modelling (longhand or shorthand), DER investment costs, DER adoption rates, and any environmental values; and
- How the business case should be reported, including nomination of the methods adopted, detailed description of the counterfactual and setting out of the various components of the value stack.

Annual publication of input assumptions

The AER should consider commissioning, on an annual basis, the development of standard assumptions (including via electricity market modelling) which may be used as inputs to DER integration cost-benefit assessments, including:

- Long run marginal costs (LMRC) and generation profiles for standard large-scale generation types (to apply in shorthand total costs method);
- Wholesale electricity prices over a long-term investment period (to apply in shorthand running costs method);
- Emission intensity of generation over a long-term investment period by region; and
- DER investment costs and (where applicable) generation profiles by region.

The assumptions should be consistent with AEMO's Integrated System Plan scenarios (including the central scenario as a minimum).

Guidance on the development of hosting capacity assessments

The AER should consider developing guidance for networks to follow in assessing the hosting capacity of their networks. DER integration business cases depend in a large part on hosting capacity: the amount of DER a network views its current system can sustain, and what it believes it will be able to accommodate in the future given some investment.

There is not a uniform way in which networks conduct hosting capacity assessments today, and stakeholders in the regulatory process have little insight (and poor knowledge of the fundamental challenge) into how networks assess hosting capacity. The ability of networks to understand hosting capacity limits is a key input into their DER integration business cases, and is also critical for many other businesses, particularly DER providers. The business prospects of solar installers, virtual power plant (VPP) developers and aggregators – among others – depend upon the ability of customers to connect and export DER.

Consequently, given the importance of hosting capacity assessments to DER integration business cases, the impact on the future business of networks and other industry participants, and the lack of uniformity and transparency in current hosting capacity assessments, we suggest that the AER consider providing guidance on how networks should analyse hosting capacity and how to communicate those findings to stakeholders.

Appendix B: AER market modelling analysis

Data

The sample period we used was the two year period from March 2018 to February 2020, and the following data was used:

- Regional total demand (NEO[75])
- Regional rooftop PV generation (AEMO)
- NEM-wide merit-order data (NEO)
- Dispatchable unit identifier (DUID) to fuel type mapping information (AER)
- DUID level fuel cost, heat rate, and operating cost information (AEMO ISP 2018)
- Regional DUID level generation target (NEO)

Assumptions

Our analysis makes the following assumptions:

1. There are no generation constraints, such as generation constrained on or off. This allows the model to focus on the dispatchable merit order.
2. The bidding behaviour of generators is static and does not respond to the changed rooftop PV generation. Therefore the analysis estimates the short-term impact of the PV generation.
3. For each trading interval, the interconnector flow sensitivity, export limit and import limit for the dispatch round are the same as for the predispatch round which is published at the beginning of the trading interval.
4. The change in regional demand (because of disappeared PV generation) does not impact the interconnector flow sensitivity.
5. For each trading interval, if the estimated regional PV-adjusted generation target is higher than its regional bid generation capacity, the region will consume all its bid capacity and then perform load shedding (as we assume existing generators do not respond to the disappeared PV generation).

Assumptions (3) and (4) allow the model to estimate the impact of PV generation on the regional net import/export level, which will further impact the regional generation target. Assumption (5) is to handle a few special cases where the PV-adjusted generation target exceeds the regional generation capacity.

[75] Intelligent Energy Systems, 'NEO Data visualisation tool', accessed April 2021.

Methodology

Step 1: Rearrange the regional generation target

Prior to modelling, we estimated the PV impact on the regional generation target. According to AEMO's demand terms document[76], the following balance equation applies for each region in each interval:

$$\begin{aligned} &Regional\ Generation\ Target\ (RGT) + Net\ Interconnector\ Targets\ (into\ the\ region) \\ &\quad = Regional\ Total\ Demand\ (RTD) + Dispatched\ Load\ (DL) \\ &\quad + Allocated\ Interconnector\ Losses\ (AIL) \end{aligned}$$

By rearranging the above equation, we have:

$$RGT = RTD + Regional\ Net\ Export\ (RNE) + DL + AIL$$

Assuming the change in PV generation does not impact the dispatched load and allocated interconnector losses, if PV generation changes, the counterfactual generation target would be:

$$RGTwithchangedPV = RTDwithcurrentPV + \Delta RTD + \Delta RNE$$

Since the rooftop PV generation is treated as negative demand in the NEM, the increase/decrease in regional PV generation decreases/increases the regional demand accordingly, then, approximately we have:

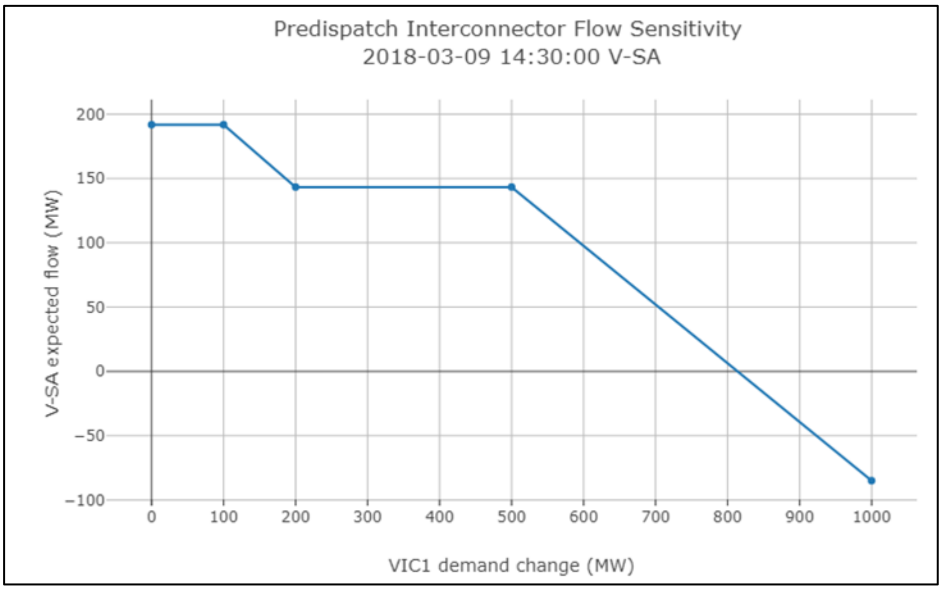
$$RGTwithchangedPV = RTDwithcurrentPV - \Delta PV + \Delta RNE$$

Step 2: Estimate the impact of PV generation on the regional export

At the beginning of each trading interval, AEMO provides predispatched flow and flow sensitivity data for each interconnector between regions. This data indicates the change in the expected interconnector flow in response to the change in the regional demand. Figure 7 provides an example, indicating the change in the expected flow from Victoria to South Australia if the regional demand in Victoria increases by 100 MW, 200 MW, 500 MW and 1,000 MW (for a particular trading interval).

[76] AEMO, 'Demand Terms in EMMS Data Model', January 2021.

Figure 7: Example of predispatch interconnector flow sensitivity



In the absence of the actual relationship between the regional demand change and the dispatch interconnector flow change, we consider using predispatch data serves as the best estimation. The expected interconnector flow does not necessarily change linearly as regional demand changes, as shown in figure 7. Therefore, instead of assuming a single linear relationship between the changing regional demand and the responding interconnector flow, a stepwise linear relationship (assuming the linear relationship between every two neighbouring reference points) may be more appropriate.

Our model uses the stepwise linear relationship (also adjusted for the interconnector export and import limits) to estimate the change in the interconnector flow as the result of the disappeared regional PV generation. This estimation is performed for each trading interval within the sample period. The model aggregates the relevant interconnectors to estimate the PV impact on the regional export.

Step 3: Run model

The modelling steps are:

1. Assign the marginal dispatch cost to each DUID using the following formula:[77]

$$MC_i = HeatRate_i \times FuelPrice_i + VarOPEX_i$$

2. For each trading interval, extract the corresponding NEM-wide merit-order data;
3. Map the DUID information to the merit-order data;

[77] As demonstrated by Borenstein, Bushnell and Wolak (2002).

4. Given the actual regional generation target (total generation target volume), extract the generation stack based on the merit-order, and calculate the modelled regional dispatch cost;
5. Given the estimated regional PV-adjusted generation target (based on the method introduced above), extract the generation stack based on the merit-order data, and calculate the modelled regional PV-adjusted dispatch cost;
6. Use the actual DUID level regional generation target data and calculate the actual dispatch cost.

The following metrics were derived from the modelling:

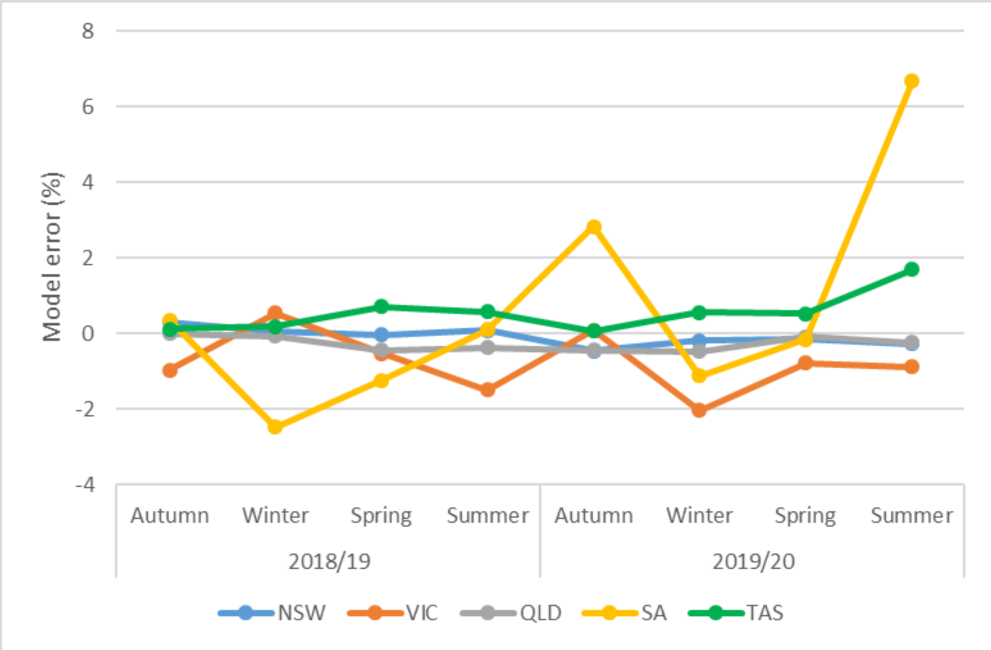
- Baseline model error: The difference between the modelled dispatch cost and the actual dispatch cost. This is used to examine the model performance to ensure the model provides meaningful results.
- Avoided dispatch cost (aggregate level): the difference between the modelled PV-adjusted dispatch cost and the modelled dispatch cost. This represents the total avoided dispatch cost due to the incremental PV generation volume.
- Avoided dispatch cost ($/MWh PV generated): the total avoided dispatch cost divided by the total incremental PV generation volume.

Results analysis

The sample case explored using the proposed model to estimate the avoided dispatch cost by comparing the dispatch cost with current PV generation to the counterfactual dispatch cost if the current PV generation was absent. The model performs well overall for most jurisdictions, with modelled dispatch cost closely tracking the actual dispatch cost. Model error was higher in 2019/20 when compared with 2018/19, however in general was less than 2% for most jurisdictions.[78] The greater model error in 2019/20 reflects the occurrence of events/constraints that impacted the dispatch order (where the dispatch result deviated more from the optimal dispatch order). A notable exception occurred in South Australia in summer 2019/20, where the model error was 6.7%. This was due to a range of market events that occurred on 31 December 2019. Figure 8 shows the model error for each jurisdiction.

[78] A positive error means that modelled dispatch cost exceeded actual dispatch cost, whereas a negative error means that modelled dispatch cost was less than actual dispatch cost.

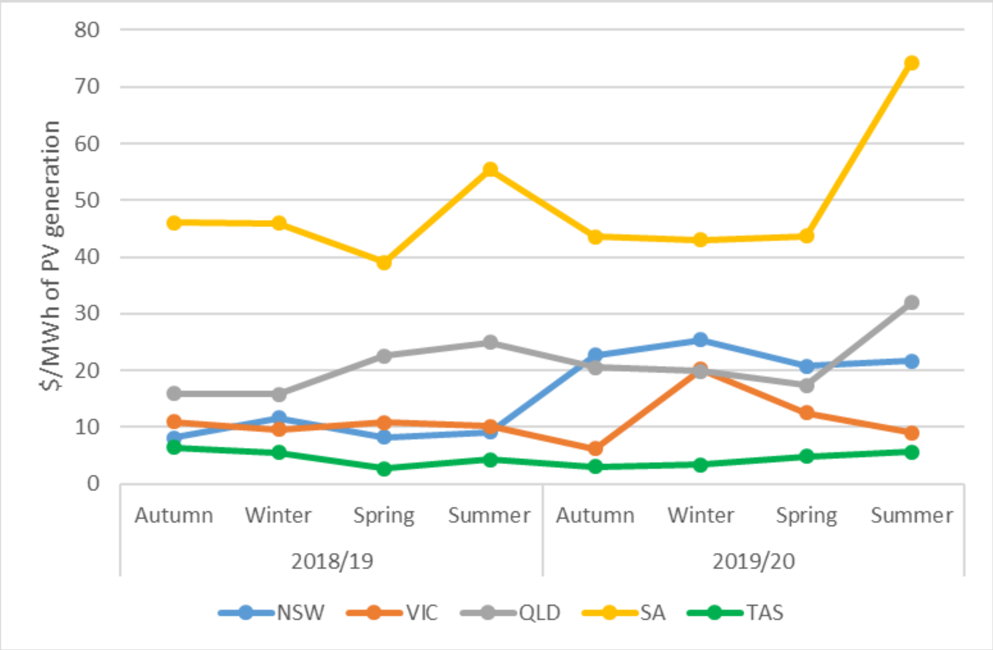
Figure 8: Model error across jurisdictions



The analysis highlights the variation in avoided dispatch costs across the jurisdictions, with avoided dispatch costs highest in South Australia and lowest in Tasmania. It also highlights that, in general, avoided dispatch costs were higher in 2019/20 than in 2018/19. The main reason for this is that the variable cost provided in the AEMO ISP increased. For example, the estimated SRMC of Loy Yang A station increased from $8.79/MWh in 2018 to $12.31/MWh in 2020.

Finally, we observe seasonal variations in avoided dispatch costs. For South Australia and Queensland, avoided dispatch costs were highest in summer in both years. Avoided dispatch costs were highest in winter in both years in New South Wales. Figure 9 shows the avoided dispatch costs for each jurisdiction.

Figure 9: Avoided dispatch costs across jurisdictions



Overall, the model performs well and provides meaningful results based on the model error metric, despite instances of greater errors for South Australia. It is difficult to directly compare the modelling results of this analysis with DNSP estimates of avoided dispatch costs, due to differences in the model target question, selection of data and forecasting assumptions.